BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

In the Matter of the Application of

HAWAIIAN ELECTRIC COMPANY, INC.
HAWAII ELECTRIC LIGHT COMPANY, INC.
MAUI ELECTRIC COMPANY, LIMITED

For Approval of the Advanced Meter Infrastructure (AMI) Project and Request to Commit Capital Funds, to Defer and Amortize Software Development Costs, to Begin Installation of Meters and Implement Time-Of-Use Rates, for Approval of Accounting and Ratemaking Treatment, and other matters.

Docket No.

2008-0303

FILED

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PUBLIC UTILITIES COMMISSION

Advanced Metering Infrastructure (AMI) Project

Application

December 1, 2008

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

In the Matter of the Application of HAWAIIAN ELECTRIC COMPANY, INC. HAWAII ELECTRIC LIGHT COMPANY, INC. MAUI ELECTRIC COMPANY, LIMITED For Approval of the Advanced Meter Infrastructure (AMI) Project and Request to Commit Capital Funds, to Defer and Amortize Software Development Costs, to Begin Installation of Meters and Implement Time-Of-Use Rates, for Approval of Accounting and Ratemaking Treatment, and other matters.	)	Docket No. 2008-0303

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PUBLIC UTILITIES COMMISSION

APPLICATION

EXHIBITS 1 - 28

VERIFICATION

and

CERTIFICATE OF SERVICE

Darcy L. Endo-Omoto
Vice President
Hawaiian Electric Company, Inc.
Hawaii Electric Light Company, Inc.
Maui Electric Company, Limited
P.O. Box 2750
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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF HAWAII

In the Matter of the Application of HAWAIIAN ELECTRIC COMPANY, INC. HAWAII ELECTRIC LIGHT COMPANY, INC. MAUI ELECTRIC COMPANY, LIMITED For Approval of the Advanced Meter Infrastructure (AMI) Project and Request to Commit Capital Funds, to Defer and Amortize Software Development Costs, to Begin Installation of Meters and Implement Time-Of-Use Rates, for Approval of Accounting and Ratemaking Treatment, and other matters.	)	Docket No. 2008-0303

APPLICATION

TO THE HONORABLE PUBLIC UTILITIES COMMISSION
OF THE STATE OF HAWAII

I

Hawaiian Electric Company, Inc. ("HECO"), Maui Electric Company, Limited ("MECO"), and Hawaii Electric Light Company, Inc. ("HELCO") (HECO, HELCO and MECO are collectively referred to as the "HECO Companies" or "Companies") respectfully request Commission approval:

(1) to commit capital funds in excess of $2,500,000 (estimated at $41,229,000 for HECO, $10,606,000 for MECO, and $13,190,000 for HELCO) for the Advanced Metering Infrastructure ("AMI") project as discussed in Section X;

(2) to defer certain computer software development costs (i.e., the "Stage 2" or

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

In the Matter of the Application of	)	
	)	
HAWAIIAN ELECTRIC COMPANY, INC.	)	Docket No.
HAWAII ELECTRIC LIGHT COMPANY, INC.	)	
MAUI ELECTRIC COMPANY, LIMITED	)	
	)	
For Approval of the Advanced Meter Infrastructure	)	
(AMI) Project and Request to Commit	)	
Capital Funds, to Defer and Amortize	)	
Software Development Costs, to Begin	)	
Installation of Meters and Implement Time-Of-Use	)	
Rates, for Approval of Accounting and Ratemaking	)	
Treatment, and other matters.	)	

APPLICATION

EXHIBITS 1 - 28

VERIFICATION

and

CERTIFICATE OF SERVICE

Darcy L. Endo-Omoto
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Hawaiian Electric Company, Inc.
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BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

In the Matter of the Application of	)	
	)	
HAWAIIAN ELECTRIC COMPANY, INC.	)	Docket No.
HAWAII ELECTRIC LIGHT COMPANY, INC.	)	
MAUI ELECTRIC COMPANY, LIMITED	)	
	)	
For Approval of the Advanced Meter Infrastructure	)	
(AMI) Project and Request to Commit	)	
Capital Funds, to Defer and Amortize	)	
Software Development Costs, to Begin	)	
Installation of Meters and Implement Time-Of-Use	)	
Rates, for Approval of Accounting and Ratemaking	)	
Treatment, and other matters.	)	

APPLICATION

TO THE HONORABLE PUBLIC UTILITIES COMMISSION
OF THE STATE OF HAWAII

I

Hawaiian Electric Company, Inc. ("HECO"), Maui Electric Company, Limited ("MECO"), and Hawaii Electric Light Company, Inc. ("HELCO") (HECO, HELCO and MECO are collectively referred to as the "HECO Companies" or "Companies") respectfully request Commission approval:

(1) to commit capital funds in excess of $2,500,000 (estimated at $41,229,000 for HECO, $10,606,000 for MECO, and $13,190,000 for HELCO) for the Advanced Metering Infrastructure ("AMI") project as discussed in Section X;

(2) to defer certain computer software development costs (i.e., the "Stage 2" or

"Application Development" costs, including the costs of designing, acquiring, installing and testing the computer software) for the Meter Data Management System ("MDMS") and accrue an allowance for funds used during construction ("AFUDC") during the deferral period (total deferred costs are estimated at $9,134,000 for HECO, $2,021,000 for MECO, and $2,385,000 for HELCO) described in Sections X and XI;

(3) to amortize the MDMS deferred costs (including AFUDC) over a 12-year period (or such other amortization period as the Commission finds to be reasonable), and to include the unamortized deferred costs (including AFUDC) in rate base, as is further explained in Sections X and XI;

(4) of cost recovery for ratemaking purposes of the remaining book value of its existing meters (that will be replaced with advanced meters) in the following manner for each of the Companies (discussed in Section XI):

(a) HECO – beginning with the receipt of the Commission's Decision and Order on a straight-line basis over a period of three years for HECO,

(b) MECO – beginning with the receipt of the Commission's Decision and Order on a straight-line basis and ending when MECO's meter installation begins, and

(c) HELCO – beginning with the receipt of the Commission's Decision and Order on a straight-line basis and ending when HELCO's meter installation begins;

(5) of cost recovery for ratemaking purposes of the capital costs associated with the purchase and installation of the new AMI meters over a seven-year period on a

straight-line basis (discussed in Section XI);

(6) for immediate approval to begin installing, on a first-come, first-served basis, advanced meters for all customers that request them and to implement time-of-use ("TOU") rates on an interim basis for customers requesting the installation of advanced meters as discussed in Sections II and XII;

(7) for expedited approval of proposed Schedule TOU-R (Residential Time-of-Use) rates for HECO, HELCO, and MECO (all three divisions) and proposed Schedule TOU-G (Small Commercial Time-of-Use Service), Schedule TOU-J (Commercial Time-of- Use Service) and Schedule TOU-P (Large Power Time-of-Use Service) rates for HELCO and MECO (all three divisions)[1] (described in Section XII);

(8) to recover all of the Companies' incremental cost associated with the AMI Project through the Renewable Energy Infrastructure Program ("REIP") surcharge ("REIP Surcharge") that is pending approval in Docket No. 2007-0416 or an AMI surcharge ("AMI Surcharge") mechanism approved by the Commission in this proceeding (discussed in Section XI);

(9) for approval of the Advanced Metering Infrastructure Equipment and Services Agreement ("Sensus Agreement") between the Hawaiian Electric Company, Inc. and Sensus Metering Systems, Inc. ("Sensus") including its terms and conditions and a finding that the arrangement is prudent and in the public interest, and a determination that the Companies may include all costs, fees and related taxes to be paid by the Companies pursuant to the Agreement in its revenue requirements for ratemaking purposes and for the purposes of determining the reasonableness

[1] All of the proposed Time-Of-Use (TOU) rates will be adjusted to align with the current Energy Cost Adjustment Clause at the respective Companies.

of the Companies' rates (described in Exhibit 1 and discussed in Section VII); and

(10) for recovery of lease expenses (based on lease payments over the term of the agreement) for the Sensus-owned, two-way radio frequency network infrastructure ("AMI Network") (the AMI Network is described in Section VII and the lease expenses are discussed in Section XI).

AMI refers to the system infrastructure that measures, collects and analyzes energy usage, on a pre-defined schedule or "on demand" basis. This infrastructure includes hardware, software, and communication systems, ultimately linking customer premise advanced electricity meters to utility-located systems. AMI provides two-way communications between the meters and systems to obtain consumption reads and voltage status at individual premises much more frequently than the Companies' existing monthly meter reading cycles.

The AMI Project will replace approximately 95-96%[2] of the commercial, industrial, and residential electric meters with AMI meters that collect and transmit interval energy use data multiple times daily[3] and on demand. The AMI Project will also include a centralized MDMS, integration of the MDMS with the Customer Information System ("CIS"), and a two-way, radio frequency ("RF") network to provide communication between the AMI meters and the MDMS. AMI meters and components

[2] HECO plans to replace 95% of its non-MV90 meter population while MECO and HELCO plan to replace 96% of their non-MV90 meter population.
[3] Time intervals between data transmission can vary due to the dynamic fashion in which the AMI Network operates.

of the AMI Network will be installed on the islands of Oahu, Maui[4], and Hawaii, and a shared MDMS will be centrally located at HECO.

The estimated number of AMI meters to be installed is as follows[5]:

Island	**Number of AMI Meters**
Oahu	293,000
Maui[6]	66,000
Hawaii	92,000
Total	*451,000*

During the six year deployment of the Companies' AMI Project, the implementation costs are estimated at $97,938,000[7] and operating costs estimated at $12,426,000[8]. Cost summaries by project subsystems and individual Companies are identified in Section X.

AMI includes the use of advanced communicating meters with TOU functionality specified in the October 20, 2008 *Energy Agreement Among the State of Hawaii, Division of Consumer Advocacy of the Department of Commerce and Consumer Affairs, and Hawaiian Electric Companies* ("HCEI Agreement").[9] In an AMI system, a communications network links endpoint devices (such as meters) and business systems to

[4] The islands of Molokai and Lanai will be examined after AMI system deployments are completed on Oahu, Maui, and Hawaii.
[5] AMI meter counts are based on the estimated meter population growth at the end of each company's meter deployment period. HECO expects to replace 95% of its non-MV90 meters with AMI meters and MECO and HELCO expects to replace 96% of their non-MV90 meters with AMI meters. Figures have been rounded in the table above.
[6] Meter replacements on Molokai and Lanai will be analyzed after meter deployments are completed on Oahu, Maui, and Hawaii. Molokai currently has 2,732 meters and Lanai has 1,710 meters. The instant application does not include AMI implementation costs or benefits for Molokai and Lanai.
[7] This figure includes capital, deferred, and expensed cost components for all three Companies.
[8] This figure includes capital, deferred, and expensed costs components for all three Companies.
[9] See, e.g., HCEI Agreement at 25 ("Upon Commission approval, AMI will be implemented as quickly as possible, along with proposals for time-of-use rates and customer electricity pricing information that facilitate substantive customer understanding and energy use management.").

allow the collection and distribution of information to customers and utilities. This enables the Companies to either participate in, or provide, demand response ("DR") programs. By providing information to customers, AMI assists customers in changing their energy usage from normal consumption patterns, either in response to changes in price, or in response to incentives designed to encourage lower energy usage use at times of peak-demand periods or during periods of low operational systems reliability.

Drivers for AMI implementation in Hawaii include significant developments in the evolution and availability of AMI-related technologies, AMI's increasing popularity on the U.S. mainland[10], and uncertainty in the future price of fuel. In addition, part of the Companies' AMI Strategy is to help meet Hawaii's electricity needs through energy efficiency and future DR programs, and to empower customers to make more intelligent energy decisions and have greater control over their electricity use and costs.

AMI has – particularly in recent years – received wide support at both state and federal levels, in the form of measures including the HCEI Agreement, Energy Policy Act of 2005, Energy Independence and Security Act of 2007, Clean Renewable Energy and Conservation Tax Act of 2007, the Emergency Economic Stabilization Act of 2008, and statutes recently enacted by the Hawaii legislature concerning the development of renewable energy and reduction of greenhouse gas emissions in Hawaii. In line with this support, AMI has also been proposed in the Companies' RPS/REIP dockets (Docket Nos. 2007-0008 and 2007-0416, respectively) as a Renewable Energy Infrastructure ("REI") Project under the Proposed REIP.

The benefits of AMI can generally be broken down into two types: (1) cost-effective operational benefits directly attributable to the AMI system (e.g., labor savings,

[10] Mainland penetration of AMI has driven product development and reduced costs.

meter accuracy gains and energy theft recovery); and (2) customer and system benefits derived from programs that the AMI system supports or provides a platform for developing (e.g., customer service, DR, distribution asset utilization and outage management), which give customers increased flexibility and satisfaction while empowering them to make wiser energy choices.

In conjunction with future DR programs, AMI will empower the Companies' customers to reduce and/or shift energy usage in response to time differentiated energy prices. Furthermore, DR technologies, such as smart programmable/controllable thermostats, smart load cycling controls and in-premise displays, will allow customers to conveniently execute their choices.

The AMI communications and smart metering infrastructure provides a foundation for the implementation of Smart Grid technology, which combines intelligent electronic devices (i.e., smart relays and distribution automation devices) and advanced applications that utilize timely data on customer loads and voltages. AMI provides unparalleled capabilities in monitoring, controlling, optimizing and automating the restoration of the electric power delivery system. Collectively, AMI and DR offer important alternatives, in addition to renewable energy, to help address global energy supply and environmental issues.

The incremental revenue requirements for the AMI Project include the estimated [net] costs to the HECO Companies of installing or acquiring the AMI platform (i.e., the costs of the advanced meters, the MDMS system, and the AMI Network services), as offset by the benefits of automating meter reading and certain field service activities, revenue enhancements from improved meter accuracy, and reduced electricity theft.

The revenue requirement analysis should not be confused with a complete business case for installing the AMI platform, which would require quantification of the costs and benefits of the programs or activities that will be enabled or facilitated by the AMI platform, including TOU pricing, DR programs such as critical peak pricing, the provision of certain ancillary services to facilitate the integration of large amounts of wind generated electricity, outage management and "Smart Grid" projects. The HECO Companies are taking steps to develop the information necessary to design the programs and activities (such as the proposed Dynamic Pricing Pilot ("DPP") program in Docket No. 2008-0074, and the Big Wind Studies) identified in the HCEI Agreement.

II

HCEI AGREEMENT

On October 20, 2008, the Governor of the State of Hawaii, the Department of Business, Economic Development and Tourism, the Consumer Advocate and the HECO Companies executed the HCEI Agreement[11] which documents a course of action to make Hawaii energy independent, and recognizes the need to maintain HECO's financial health in order to achieve that objective. With respect to AMI, the Energy Agreement states that:

> Advanced Metering Infrastructure is a critical component of a number of important aspects of the Clean Energy Initiative. The parties believe that AMI will help customers manage their energy use more effectively. To that end, the parties agree on the following:
>
> 1. Hawaiian Electric will apply to the Commission by November 30, 2008, for immediate approval to begin installing, on a first-come, first-served basis, advanced meters for all customers that request them. The application will also seek expedited approval to fully implement time-of-use rates on an interim basis for the customers requesting the installation of advanced meters. Unless the Commission identifies a compelling reason to

[11] Section VIII C.1. discusses the Hawaii Clean Energy Initiative in greater detail.

do otherwise, all customers having advanced meters will be given the utility time-of-use or dynamic rate options and shall have to affirmatively opt out of the rate option.

2. The meters and associated costs will be paid for through the CEIS, until such costs are embedded and recovered in the utilities' base rates in future rate cases.

3. By December 31, 2008, Hawaiian Electric will file a full application to install advanced meters to remaining customers and the communication and meter data management system, including the necessary software and appropriate pricing programs. The PUC application will identify the desired goals, business purposes, functionality and cost for advanced meters and the identification of a meter data management system with associated costs to purchase and install that will achieve the desired goals and purposes, including a schedule for acquisition and installation of remaining meters and the customers to be served.

4. Upon Commission approval, AMI will be implemented as quickly as possible, along with proposals for time-of-use rates and customer electricity pricing information that facilitate substantive customer understanding and energy use management.

5. Hawaiian Electric will minimize the financial impacts on low income and disadvantaged customers who have limited options through a combination of tiered rates and lifeline rates.

6. The Hawaiian Electric utilities working with external experts will submit to the Commission an evaluation of the effectiveness of the utilities' time-of-use rates and shall determine whether any changes are needed to the energy information communications and time-of-use rates to improve customers' energy responsiveness. The utilities will complete this evaluation by December 31, 2009 and will submit a second report 1 year after the full deployment of AMI.

7. Beginning January 1, 2009, the utility will submit an annual report to the Commission on the number of customers currently served, number who opted out, customer load response, impact of time-of-use rates on customer's monthly bills and feedback received from customers.

HCEI Agreement at 24-25.

III

HECO COMPANIES

HECO, whose principal place of business and whose executive offices are located at 900 Richards Street, Honolulu, Hawaii (with other administrative offices at 820 Ward

Avenue (Ward Avenue Complex) and 220 South King Street (Central Pacific Plaza)), is a corporation duly organized under the laws of the Kingdom of Hawaii on or about October 13, 1891, and is now existing under and by virtue of the laws of the State of Hawaii. HECO is an operating public utility engaged in the production, purchase, transmission, distribution, and sale of electricity on the Island of Oahu.

HELCO, whose principal office is located at 1200 Kilauea Avenue, Hilo, Hawaii (with remote offices at 66-1591 Kawaihae Road, Waimea and 74-5519 Kaiwi Street, Kailua Kona), is a corporation duly organized under the laws of the Republic of Hawaii on or about December 5, 1894, and is now existing under and by virtue of the laws of the State of Hawaii. HELCO is an operating public utility engaged in the production, purchase, transmission, distribution, and sale of electricity on the Island of Hawaii.

MECO, whose principal place of business and whose main administrative office is located at 210 West Kamehameha Avenue, Kahului, Maui, Hawaii (with remote offices at 32A Ulili Street, Kaunakakai, Molokai and 1001 North Miki Road, Lanai City, Lanai), is a corporation duly organized under the laws of the Territory of Hawaii on or about April 28, 1921, and is now existing under and by virtue of the laws of the State of Hawaii. MECO is an operating public utility engaged in the production, purchase, transmission, distribution and sale of electricity on the Island of Maui; the production, transmission, distribution, and sale of electricity on the Island of Molokai; and the production, distribution, and sale of electricity on the Island of Lanai.

IV

CORRESPONDENCE

Correspondence and communications in regard to this Application should be addressed to:

Dean K. Matsuura
Manager, Regulatory Affairs
Hawaiian Electric Company, Inc.
P. O. Box 2750
Honolulu, Hawaii 96840-0001

with copies of such correspondence and communications sent to:

Thomas W. Williams, Jr., Esq.
Damon L. Schmidt, Esq.
Goodsill Anderson Quinn & Stifel
Alii Place, Suite 1800
1099 Alakea Street
Honolulu, Hawaii 96813

V

AUTHORIZATIONS

The Companies request:

A. Approval to commit capital funds for the AMI Project estimated at $41,229,000 for HECO, $10,606,000 for MECO, and $13,190,000 for HELCO) pursuant to Decision and Order No. 21002 (Docket No. 03-0257) ("D&O 21002") "For Exemption From and Modification of General Order No. 7, Paragraph 2.3 (g), Relating to Capital Improvements."[12]

[12] D&O 21002 revised Paragraph 2.3 (g) to read "Proposed capital expenditures for any single project related to plant replacement, expansion or modernization in excess of $2,500,000 excluding customer contributions, or 10 per cent of the total plant in service, whichever is less, shall be submitted to the Commission for review at least 60 days prior to the commencement of construction or commitment for expenditure, whichever is earlier."

This project does not involve construction of high voltage, overhead transmission lines and is, therefore, not subject to Hawaii Revised Statues ("HRS"), Sections 269.27.5 and 269.27.6.

B. Approval of the Sensus Agreement, executed on October 1, 2008, with Sensus including: (1) approval of its terms and conditions and a finding that the arrangement is prudent and in the public interest; and (2) a determination that HECO may include all costs, fees and related taxes to be paid by HECO pursuant to the Sensus Agreement in its revenue requirements for ratemaking purposes and for the purposes of determining the reasonableness of HECO's rates. (If such an order is not obtained within 12 months of the filing of this Application, then HECO or Sensus may, by written notice delivered within 30 days of such date, declare the Sensus Agreement null and void. This Sensus Agreement is confidential and proprietary and a copy will be provided after a protective order is issued in this Docket.) See Exhibit 1.

C. Approval to defer certain computer software development costs (i.e., the "Stage 2" or "Application Development" costs, including the costs of designing, acquiring, installing, and testing the computer software) for the MDMS portion of the AMI Project, and to accumulate AFUDC during the deferral period (total deferred costs estimated at $9,134,000 for HECO, $2,021,000 for MECO, and $2,385,000 for HELCO).

D. Approval to amortize (and recover the cost of) the deferred software development costs (including AFUDC) over a 12-year period (or such other amortization period as the Commission finds to be reasonable), and to include the unamortized deferred costs (including AFUDC) in rate base. This approval is requested pursuant to Decision and Order No. 18365 dated February 8, 2001 in Docket No. 99-0207 (HELCO's

2000 test year rate case), which ordered that Commission approval is required prior to incurring software development costs to be deferred and amortized for ratemaking purposes.

E. Approval to recover the cost of the remaining book value of the Companies' existing meters (that will be replaced with advanced meters) over an accelerated period (estimated to between three to five years beginning with the receipt of the Commission's Decision and Order), pursuant to HRS § 269-16(b)(2)(D).

F. Approval to recover the costs of the Companies' advanced meters installed in connection with the AMI Project over a seven-year, accelerated period, pursuant to HRS § 269-16(b)(2)(D).

G. Approval to defer certain AMI Project costs and recover such costs through the proposed REIP Surcharge, as pursuant to the respectfully requested REI Program proposed in the REIP docket, Docket No. 2007-0416, or in the alternative, through an AMI Surcharge.

H. As provided for in the HCEI Agreement and further detailed in Section II, the Companies request: (a) immediate approval to begin installing, on a first-come, first-served basis, advanced meters for all customers that request them; (b) expedited approval to fully implement TOU rates on an interim bases for the customers requesting the installation of advanced meters; and (c) approval to install advanced meters to remaining customers and the AMI Network and MDMS, including the necessary software and appropriate pricing programs. Authorization to implement the TOU rates is requested pursuant to HRS § 269-16(b) and Hawaii Administrative Rules ("HAR") § 6-61-86.

VI

EXHIBITS

The following exhibits are provided in support of this Application:

Exhibit 1	Sensus Agreement Summary
Exhibit 2	AMR versus AMI
Exhibit 3	Technology Selection
Exhibit 4	Options to Empower the Customer with Information
Exhibit 5	High Level View of the Pilot FlexNet System
Exhibit 6	AMI Pilot System on Oahu - Meters and Tower Gateway Basestations
Exhibit 7	Enspiria Solutions-Qualifications and References
Exhibit 8	Meter Data Management System (MDMS)
Exhibit 9	AMI Systems Integration and OMS Support
Exhibit 10	Sensus Metering Systems Products
Exhibit 11	FlexNet AMI Network Details
Exhibit 12	HANs and In-Premise Displays
Exhibit 13	Sensus Demand Response and Smart Grid White Paper
Exhibit 14	Change Management
Exhibit 15	AMI Benefits
Exhibit 16	Accuracy Tests-Electro-Mechanical and Sensus AMI Meters
Exhibit 17	Energy Theft Estimates
Exhibit 18	Overall AMI Project Schedule
Exhibit 19	Project Cost and Quantifiable Benefits Tables
Exhibit 20	REIP Program
Exhibit 21	Rate Impact of AMI

Exhibit 22	Revenue Requirements Calculation
Exhibit 23	Need for Timely Cost Recovery
Exhibit 24	Accounting and Ratemaking Treatment
Exhibit 25	Proposal for TOU Options and Rate Schedule
Exhibit 26	HECO Preferred Stock, Long-Term Debt and Hybrid Securities
Exhibit 27	HELCO Preferred Stock, Long-Term Debt and Hybrid Securities
Exhibit 28	MECO Preferred Stock, Long-Term Debt and Hybrid Securities

VII

AMI PROJECT DESCRIPTION

A. OVERVIEW

AMI provides two-way communications between utilities and customer meters to allow utilities to obtain consumption reads and voltage status at individual premises much more frequently than the existing monthly meter reading cycles, as well as "on demand."[13] The AMI Project will replace approximately 95-96% of the commercial, industrial, and residential electric meters with AMI meters that collect and transmit

[13] "Advanced metering infrastructure," as defined by FERC is:

> . . . a metering system that records customer consumption (and possibly other parameters) hourly or more frequently and that provides for daily or more frequent transmittal of measurements over a communication network to a central collection point. AMI includes the communications hardware and software and associated system and data management software that creates a network between advanced meters and utility business systems and which allows collection and distribution of information to customers and other parties such as competitive retail providers, in addition to providing it to the utility itself.

FERC Staff Report, Assessment of Demand Response & Advanced Metering, Docket No. AD-06-2-000, August 2006 ("FERC Staff Report") Appendix A (Glossary). AMI goes beyond traditional automated meter reading ("AMR"), in which monthly billing reads are captured. AMI also goes beyond Drive-By AMR in that interval data is being captured and transmitted multiple times daily. The capture of interval data, integration with the Company's CIS, and OMS support will provide many quantifiable and intangible benefits, serve to enable other applications such as DR and Dynamic Pricing, and support Smart Grid capabilities in the future. A more detailed description of the differences between AMR and AMI is attached hereto as Exhibit 2.

interval energy use data multiple times daily[14] and on demand[15]. The AMI Project will also include a centralized MDMS, integration of the MDMS with the Companies' CIS, and an AMI Network to provide communication between the AMI meters and the MDMS. AMI meters and components of the AMI Network will be installed on the islands of Oahu, Maui[16], and Hawaii. Residential AMI meters will be installed by (1) a meter installation vendor (to be selected via a request for proposal selection process), (2) Companies' internal labor force, or (3) a combination of the two. The Commercial and Industrial (C&I")AMI meters[17] will be installed by HECO Companies' internal labor force.

The Companies' AMI Network will use a fixed, RF technology[18]. The AMI Network will be owned, operated, and maintained by Sensus and leased by the HECO Companies per the Sensus Agreement executed by the Companies. A shared MDMS will be centrally located at HECO.

Overall, HECO is planning for a six-year AMI Project implementation, beginning in 2010[19]. The AMI Project will begin with the development of the first phase of the MDMS in 2010 at HECO's data center on Oahu. The installation of Oahu's AMI Network will occur incrementally, beginning in November 2010 and progressing through August 2013. Full-scale meter deployment on Oahu will begin in May 2011 and end in December 2013. The installation of Maui's AMI Network will occur incrementally,

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[14] Time intervals between data transmission can vary due to the dynamic fashion in which the AMI Network operates.

[15] HECO plans to replace 95% of its non-MV90 meter population while MECO and HELCO plan to replace 96% of their non-MV90 meter population.

[16] The islands of Molokai and Lanai will be examined after AMI system deployments are completed on Oahu, Maui, and Hawaii.

[17] Current Transformer (CT)-rated meters.

[18] Exhibit 3 describes available AMI technologies, including further details about the Companies' selected FlexNet technology from Sensus.

[19] Assuming Commission approval of the AMI application by January 2010.

beginning in November 2013 and progressing through September 2014. Full-scale meter deployment on Maui will begin in April 2014 and end in December 2014. The installation of the AMI Network on the island of Hawaii will occur incrementally, beginning in October 2014 and progressing through August 2015. Full-scale meter deployment on Hawaii will begin in April 2015 and end in December 2015.

Functionally, the AMI system will be designed to provide: (1) a two-way RF network infrastructure and communication path to AMI residential and C&I electric meters[20]; (2) the ability to acquire interval data (15-minute or 1-hour) from all AMI meters; (3) the ability to support future programs such as dynamic pricing and peak time rebate programs; and (4) the ability to improve distribution system operations through enhanced outage and restoration reporting.

The primary goals of the AMI Project are customer empowerment, improved customer service and cost savings, by providing or enabling capabilities such as:

- Advanced meter reads (monthly, on-demand, interval data, etc.);
- Remote disconnects/reconnects;
- Voltage level monitoring at the customer premise level;
- Power failure and restoration reporting (outage management support);
- Tamper detection;
- Energy theft recovery;
- Improved grid operations;
- CIS Integration; and
- Future DR programs.

The AMI Network enables the collection and distribution of information to customers and utilities in order to enable customers to participate in, and allow utilities to

[20] These meters will be provided to an estimated 95% of the non-MV90 meters on Oahu and 96% of the non-MV90 meters on Maui and the island of Hawaii.

provide future DR programs. By providing information to customers, AMI will encourage customers to reduce electricity consumption and modify their historic consumption patterns, either in response to changes in price, or in response to incentives designed to encourage lower electricity usage during peak demand periods or during periods of low operational systems reliability. Exhibit 4 illustrates alternative ways in which information could be provided to customers in the future[21].

B. AMI PILOT ACTIVITIES

In addition to earlier investigations into cellular, Wi-Fi, and Broadband Over Powerline ("BPL") technologies, HECO has conducted three AMI pilot projects: (1) an initial investigation into the functionality of Sensus AMI technology with 500 AMI meters on Oahu and two Tower Gateway Basestation ("TGB") sites located atop the Prince Kuhio Hotel in Waikiki and the Five Regents condominium in Salt Lake; (2) an investigation into the ability of Sensus' AMI technology to collect data reliably for monthly billing purposes in three meter reading routes, involving over 3,000 residential and commercial meters in the Ocean Pointe area along with a third TGB tower at Mauna Kapu in the Makakilo area; and (3) the addition of two more TGB sites at Koko Head and Pu'u Papa'a, involving approximately 400 residential meters to collect baseline electricity profiles to support a Dynamic Pricing Pilot program. HECO is continuing to evaluate, develop and demonstrate AMI (including MDMS products) as part of the Companies' pilot projects.[22]

[21] The Companies are working with Sensus and other suppliers to develop and test such devices as "In-Premise Displays" and Smart Thermostats that provide such information. In addition, the Companies plan to develop a web portal to provide information to customers.

[22] A high level view of the pilot FlexNet system that resulted from the Companies' ongoing pilot activities on Oahu is attached hereto as Exhibit 5.

Additional AMI meters were installed to support HECO's 2008-2009 Class Load Study and to further explore AMI Network coverage and performance in 2007. In October and November 2008, HECO installed an additional 1,100 AMI meters in the Palolo, Tantalus, and Pauoa areas to investigate performance in valley and mountainous terrain[23]. Approximately 7,700 AMI meters have been deployed to date.[24]

In addition to the AMI pilot meter installations described above, HECO is conducting pilot evaluations of two leading MDMS software products. An AMI consultant, Enspiria Solutions, Inc.[25], was hired by HECO to participate in discussions with various HECO departments (including Customer Service and Information Technology & Services Departments and the Customer Field Services Division), prepare preliminary MDMS requirements, and assist the Companies in selecting several MDMS software vendors[26]. The MDMS pilot evaluations will examine interface requirements and unique operational needs identified by the Companies' staff as they work with actual MDMS products. Exhibit 8 provides additional details on the MDMS pilot projects.

Hands-on experience with meter, network, and MDMS systems and products in advance of full-scale AMI deployment will minimize business risks in the full-scale deployment of AMI.

C. PROJECT SUBSYSTEMS

The AMI Project can be organized into three subsystems:

1. AMI Meters

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[23] These AMI meters were new Sensus iConA residential meters. The Companies' operational experience with over-the-air billing from Sensus meters was previously limited to Ocean Pointe, which is flat, open terrain in West Oahu.

[24] These figures are current as of November 10, 2008. An earlier snapshot of the geographic deployment of AMI meters on Oahu is attached hereto as Exhibit 6.

[25] Qualifications of and references for Enspiria Solutions, Inc. are provided as Exhibit 7.

[26] Due to the continuing evolution of the AMI marketplace, the Companies will continue to monitor and evaluate other MDMS candidates.

2. AMI Network

3. MDMS.

During the AMI Project, the HECO Companies will purchase and install AMI meters on the islands of Oahu, Maui, and Hawaii; purchase and install the computer equipment to be located at HECO to support the MDMS; secure AMI Network services through Sensus; and issue a contract to a Systems Integrator ("SI") who will have turnkey responsibility[27] for the Companies' MDMS and all required integration with the Companies' systems. (Exhibit 9 describes the SI role further.) End-use devices such as in-premise displays, smart thermostats and load control switches may be used in future[28] program offerings enabled by AMI.

1. <u>AMI Meters</u>

Analogous to the consumer electronics business, the price of AMI meters has decreased dramatically in recent years while the meters' capabilities have increased.[29] AMI meter capabilities are being driven by the purchasing power of numerous large utilities coupled with federal energy policies (e.g., the Energy Policy Act of 2005 and Energy Independence and Security Act of 2007) and guidance from various State regulatory commissions. In addition, the HCEI Agreement supports the implementation of AMI, and recognizes that AMI "is a critical component of a number of important aspects of the Clean Energy Initiative." HCEI Agreement at 24.

[27] Including procurement of the MDMS software.
[28] This application does not include end-use devices such as in-premise displays, smart thermostats, or load control switches within the scope of the AMI Project.
[29] A description of the features, products and capabilities of the AMI meters available from the Companies' AMI meter vendor, Sensus Metering Systems, is provided as Exhibit 10. Exhibit 10 contains confidential and proprietary information and will provided after a protective order is issued in this docket.

As discussed above, HECO has been testing and deploying residential and commercial AMI meters manufactured by Sensus in its pilot projects. HECO has also completed the initial installation of an advanced version of the Sensus iCon meter, namely the iConA (residential, single phase). In 2009, HECO anticipates installing and field testing the Sensus iConAPX (advanced, three phase commercial and industrial) meter[30] while further testing Elster A3 C&I meters equipped with FlexNet communication boards.

In addition, through industry networking, HECO has established a collaborative relationship with the Southern Company ("Southern"), Portland General Electric ("PGE"), and Alliant Energy ("Alliant") to share knowledge and experiences regarding Sensus AMI products. Southern signed a Definitive Agreement with Sensus in January 2008 to purchase up to 4,000,000 Sensus meters and is now in a full deployment phase with over 100,000 Sensus iConA meters already in the field. PGE and Alliant are in their System Acceptance Phase presently and expect to be in full deployment mode in the near future.

The Companies executed a comprehensive[31] Sensus Agreement on October 1, 2008, under which the Companies will purchase residential and commercial AMI meters. A summary of the agreement is provided in Exhibit 1. The Sensus Agreement is

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[30] The Companies are currently using several generations of the iCon residential AMI meter as well as the FlexNet-equipped Elster A3 C&I meter as part of its AMI pilot projects. The iCon residential AMI meter will be supplanted by the iConA while the FlexNet-equipped Elster A3 will continue to complement the Sensus iConAPX Commercial/Industrial AMI meter in the future. The Sensus iConAPX meter was recently received for initial field trials by the Southern Company and HECO will be monitoring their experience with the Sensus iConAPX in addition to conducting its own in-house testing and field trials. Second sources for the iCon A are in development from General Electric and Landis & Gyr. Details concerning the iCon A and iCon APX meters are provided in Exhibit 10.

[31] The Sensus AMI meters will have a one year warranty and an expected life of 15 years. In addition, based on data provided by Sensus, the Companies anticipate a meter failure rate of 1% per year.

confidential and proprietary and a copy will be provided separately after a Protective Order is issued in this docket.

2. AMI Network

The AMI Network is a robust two-way, RF communications technology designed to maximize service area coverage while minimizing infrastructure hardware requirements. The AMI Network consists of TGBs, a Regional Network Interface ("RNI"), FlexNet Network Portals ("FNP") and FlexNet Remote Portals ("FRP").[32]

The Companies' AMI Network will use licensed RF band technologies (centered at 900 MHz) to enable two-way communications between the AMI meters, RNI, and the MDMS to allow collection and distribution of information and commands between the HECO Companies and their customers[33].

The AMI Network will be installed, owned, operated, and maintained by Sensus. The Companies will pay a monthly per endpoint fee[34] for the use of the AMI Network. Based on the provisions of the contract, the monthly fee for the use of the AMI Network constitutes an operating lease for book accounting purposes.

The placement of TGBs in the AMI Network design fosters overlapping coverage in order to achieve signal redundancy. The typical range for a single TGB is 15 miles, and the network design is based on achieving an overlap coverage ratio of approximately 1.5. In other words, having access to more than one TGB site improves AMI network reliability.

Sensus' initial network design calls for 25 TGBs: 15 on Oahu, 3 on Maui, and 7 on Hawaii. This network will provide coverage such that 95-96% of the Companies'

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[32] Illustrations of typical TGB and RNI hardware are provided in Exhibit 11.
[33] Commands include the remote upgrading of meter firmware and configuration.
[34] The Sensus Agreement defines the terms and conditions for the AMI Network.

commercial, industrial, and residential meters will have sufficient AMI Network coverage, and can be replaced with AMI meters.[35] Further details regarding the Sensus AMI Network technology are provided as Exhibit 11.

In cases where an AMI meter cannot reliably communicate directly with a TGB, messages can be automatically relayed by a "Buddy Meter" to the TGB via the *mpass*[36] channel. If a Buddy Meter is not available, a FNP or FRP can be installed to relay the message directly to the TGB. This might occur in certain low density or isolated (geographically or topographically) areas, where it may be economically impracticable to install a TGB, given the small number of customers that the TGB would serve.

3. MDMS

The MDMS hardware will consist of multiple computer servers (application, web, and database), networking equipment, and the associated computer operating system.

The Companies' MDMS will be implemented in three phases and prior to the mass deployment of AMI meters[37].

HECO plans to hire an experienced SI, selected through a request for proposal process, to act in the role of a prime contractor with full responsibility for the MDMS software including integration of the MDMS with the RNI and CIS. The use of an SI will mitigate MDMS implementation risks and project delays and the SI will be required to

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[35] In the Companies' response to LOL-IR-15 in the REIP docket, Docket No. 2007-0416, it was indicated that 90% of the meters would be replaced. This has been revised to reflect the final Sensus network design study and excludes the Companies' MV90 meters.

[36] "mpass" denotes Message Pass (mpass) Communication Mode: Indirect communication through a "buddy" device such as another AMI meter or a FNP/FRP repeater device.

[37] A high-level view of the MDMS architecture and how it can be integrated with other processes such as CIS and OMS is provided as Exhibit 9.

provide a performance guarantee[38]. Further details concerning integration of the MDMS with the Companies' RNI and CIS are provided as Exhibit 9.

The MDMS application is the data "bucket" that captures the large volumes of data generated by the AMI meters. The use of an MDMS can have a significant impact on operational efficiencies, customer service, energy forecasting, and distribution system reliability. At a minimum, an MDMS provides a database repository that automates and streamlines the complex process of collecting meter data from multiple collection technologies and delivering that data in the appropriate format to the billing system. Specific MDMS functions include: (1) collection system integration; (2) validation, estimation and editing; (3) versioned data storage; (4) calculation and aggregation; and (5) data exports and interfaces. Further details regarding these functions are provided as Exhibit 8.

In contrast to today's largely manual billing processes, the AMI system will generate a far greater volume of meter data. In addition, the MDMS will ultimately handle the storage and distribution of non-billing data such as outage alarms, tamper alarms and DR events. The MDMS must also be designed with the capability to meet future needs, including applications which are not initially implemented such as the Smart Grid and DR.

The collection, management and enterprise-wide application of meter-based data will enable the Companies to more effectively deliver strategic, societal and operational benefits to various stakeholders, including:

- Consolidated usage data in a single repository enabling critical knowledge to be shared easily across organizational boundaries;

[38] The use of an SI in a prime contractor capacity and folding the MDMS responsibility within its scope of work entails an added risk premium to the MDMS system integration base cost.

- Enhanced utility business processes and customer service;
- Improved regulatory and compliance reporting;
- Optimized utility operational efficiency and reliability;
- Empowerment of customers to make informed decisions on how and when they use electricity; and
- Creation of a platform to provide effective pricing programs based on the interval data captured by the AMI system.

The MDMS will interface with the Sensus RNI and the Companies' CIS. At HECO, the MDMS will eventually support HECO's Outage Management System ("OMS"), although, the current AMI Project will focus on the RNI and CIS interfaces and support for OMS will be addressed in the future[39]

D. INFORMATION ACCESS

AMI will empower customers to make more intelligent energy decisions and have greater control over their electricity use and costs. Customer access to electricity consumption will be provided through a web portal that displays time-differentiated electricity consumption. For customers without Internet access, HECO is investigating the use of "In-Premise" displays that can communicate directly with the AMI Network or through a Home Area Network ("HAN")[40]. Additional details concerning these technologies are provided as Exhibit 4, Exhibit 12, and Exhibit 13

E. END-USE DEVICES

In addition to providing customers with information regarding their energy consumption, AMI technologies could support direct load control using the AMI Network. Devices such as "ZigBee" HANs and FlexNet smart thermostats and load

[39] OMS integration will be requested in a separate application.

[40] The instant application does not request approval for provision of "in-premise" displays to customers. This would be a future request to the Commission.

control switches are in development by several vendors to support DR programs, including Sensus (see Exhibit 13).

F. CHANGE MANAGEMENT

Implementation of AMI and the technologies enabled by AMI (e.g., DR and Smart Grid) will result in changes to the Companies' business and operations paradigms, business organization and processes, customer strategies, resource planning, energy management policies, engineering practices, service reliability, and safety management. Consequently, effective management of these organizational changes (i.e., "change management") will play a key role in the Companies' successful AMI implementation. To that end, as part of the AMI Project, the Companies are mapping out a comprehensive AMI Change Management Plan focusing on the impacts of process changes on the Companies' organizations and employees, and communications with the internal and external stakeholders in the AMI Project. Additional details regarding the AMI Change Management Plan are provided as Exhibit 14.

VIII

PROJECT NEED AND SYSTEM REQUIREMENTS

A. INTRODUCTION

AMI provides two-way communications between the utility and customer meters to allow the utility to obtain consumption reads and voltage status at individual premises much more frequently than the monthly billing cycle, and "on demand." These capabilities can allow the Companies to enhance customer service, revenue management and distribution operations, and support outage management.

In conjunction with a future DR program, AMI will empower the Companies' customers to reduce and/or shift energy usage in response to time-differentiated energy prices. Further, DR technologies, such as smart programmable/controllable thermostats,[41] smart load cycling controls,[42] in-premise displays, etc., can allow customers to execute their choices conveniently.

The AMI communication and smart metering infrastructure also provides a foundation for the implementation of Smart Grid technology. Smart Grid technology combines intelligent electronic devices (i.e., smart relays and distribution automation devices) and advanced applications that utilize timely data on customer loads and voltages. The Smart Grid promises unparalleled capabilities in monitoring, controlling, optimizing and automating the restoration of the electric power delivery system. Collectively, AMI and DR offer important alternatives, in addition to renewable energy, to help address global energy supply and environmental issues.

In short, the implementation of AMI is being driven by significant developments in the evolution and availability of AMI-related technologies, AMI's increasing popularity on the U.S. mainland[43], and uncertainty in the future price of fuel. AMI has – particularly in recent years – received wide support at both state and federal levels. In line with this support, AMI is "a critical component of a number of important aspects" of

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[41] "Smart thermostats" are not a required component of AMI, although they may offer benefits for DR in addition to those possible with AMI alone. See Nancy Brockway, Advanced Metering Infrastructure: What Regulators Need to Know About Its Value to Residential Customers, Nat'l Regulatory Research Inst., February 13, 2008 ("NRRI Paper") at 10.

[42] Utilities can use AMI as a convenient network to signal direct load control devices at times of peak demand, but AMI is not required to perform this function. Conversely, a utility can install AMI without installing direct load control devices on customer end uses. NRRI Paper at 10.

[43] Mainland penetration of AMI has driven product development and reduced costs.

the HCEI Agreement.[44] AMI has also been identified in the Companies' RPS/REIP dockets as a REI Project under the REIP.

B. PROJECT TIMING

It is important for the HECO Companies to proceed now with the AMI Project. First, as further discussed below, Section 14 of the HCEI Agreement recognizes that "Advanced Metering Infrastructure is a critical component of a number of important aspects of the Clean Energy Initiative." HCEI Agreement at 24. Thus, Section 14 provides that "[u]pon Commission approval, AMI will be implemented as quickly as possible, along with proposals for time-of-use rates and customer electricity pricing information that facilitate substantive customer understanding and energy use management." Id. at 25.

In addition, proceeding with AMI now will help the Companies to empower customers to make more intelligent energy decisions and have greater control of their electricity use and costs.

Moreover, substantial developments in the evolution of metering technology (both in terms of price and capability) have enabled the HECO Companies' to recently execute the Sensus Agreement, which provides favorable pricing. The data and communications capabilities inherent in the Sensus Agreement will give customers on Oahu, Maui and the Hawaii a platform upon which to build a number of programs aimed at managing overall energy costs. In the future, technologies enabled by AMI will allow customers' appliances to receive and react to real time energy prices[45]. Some of these technologies will take time to be developed and tested, but others, such as TOU and dynamic pricing,

[44] HCEI Agreement at 24.
[45] Appliance Interface for Grid Interface, Grid-Interop, November 7-9, 2007, Albuquerque, NM.

are ready to roll out immediately, and are capable of providing significant customer benefits.

Also, the cost of electricity and gas has risen significantly in recent years, thereby driving the need for detailed consumption data for the Companies, their ratepayers and the State of Hawaii in general. Although world oil costs dropped recently, they are still high and there is no reason to believe that future oil prices will not increase over the life of the AMI Project.

Thus, AMI will help to facilitate important alternatives, in addition to renewable energy, to help address global energy supply and environmental issues.

C. SUPPORT FOR AMI

Against this backdrop, it should not be surprising that there is wide support for AMI at both state and national levels.

On the state level, the HCEI Agreement was executed on October 20, 2008, in order that Hawaii "move more decisively and irreversibly away from imported fossil fuel for electricity and transportation and towards indigenously produced renewable energy and an ethic of energy efficiency." HCEI Agreement at 1. In addition, Hawaii has enacted a number of statutes supporting the development of renewable energy including Hawaii's Renewable Portfolio Standards ("RPS") law, and, more recently, Acts 177 and 234, passed in 2007 by Hawaii's 24th Legislature.

On the national level, further support for AMI can be found in: (1) Congressional legislation such as the Energy Policy Act of 2005 ("EPAct 2005"),[46] the Energy

[46] EPAct 2005 added five new standards to the ten standards outlined previously in the Public Utility Regulatory Policies Act ("PURPA") of 1978 and the Energy Policy Act of 1992. These standards were added to PURPA § 111(d), 16 U.S.C. § 2621(d).

Independence and Security Act of 2007 ("EISA"),[47] and in the Emergency Economic Stabilization Act of 2008 ("EESA"),[48] supporting time-based pricing, other forms of DR and Smart Grid technologies; (2) the policies of the National Association of Regulatory Utility Commissions ("NARUC"), which on February 21, 2007, adopted a resolution for the removal of barriers to AMI implementation;[49] and (3) orders and reports of the Federal Energy Regulatory Commission ("FERC"), which have recognized the need for additional renewable energy transmission infrastructure, and the fact that, to a degree, AMI-supported DR can serve as a substitute for such infrastructure.[50]

1. Hawaii Clean Energy Initiative

On January 28, 2008, the State of Hawaii and U.S. Department of Energy signed a memorandum of understanding ("MOU") establishing the HCEI which provided in part:

> It is estimated that Hawaii can potentially meet between 60 and 70 percent of its future energy needs from clean, renewable energy sources. However, achieving this level market of penetration will require substantive transformation of the financial, regulatory, legal, and institutional systems that govern energy planning and delivery within the State.

As a result of the MOU, the stated created working groups to address, among other things: (1) the use of renewable energy at remote locations; (2) transmission and distribution improvements, grid management improvements, and energy storage to ensure that the existing and future infrastructure facilitates optimal use of renewable energy resources and readily adapts to and incorporates new developments in system planning and transmission technologies while maintaining system reliability; (3) the development

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[47] Pub. L. No. 110-140, H.R. 6.
[48] H.R. 1424, 110th Cong., 2d Sess.
[49] NARUC Resolution to Remove Regulatory Barriers To the Broad Implementation of Advanced Metering Infrastructure, adopted February 21, 2007 ("NARUC Resolution").
[50] See, e.g., Promoting Transmission Investment through Pricing Reform, Order No. 679, 71 Fed. Reg. 43,294 (July 31, 2006, FERC Stats. & Regs. ¶ 31222 2006) ("Order 679"); FERC Staff Report, Assessment of Demand Response & Advanced Metering, Docket No. AD-06-2-000, August 2006.

of innovative public and private financing vehicles for alternative energy sources and clean technologies at the state and county levels; and (4) design and enactment of comprehensive regulatory mechanisms that provide appropriate incentives for all stakeholders in the energy supply chain to proactively transition to a renewable energy-based future.

A product of the HCEI, the HCEI Agreement is a commitment on the part of the State and the HECO Companies to accelerate the addition of new, clean resources on all islands; to transition the HECO Companies away from a model that encourages increased electricity usage; and to provide measures to assist consumers in reducing their electricity bills. See HCEI Agreement at 1-2.

The proposed AMI Project is reasonable in light of the HCEI and the State's movement towards self-sufficiency. AMI is specifically included in Section 14 of the HCEI Agreement as one of the HCEI project proposals that are known today, with the goal of bringing the maximum number of projects and renewable capacity on-line as quickly as possible subject to Commission approval, contract negotiations, and grid integration feasibility.

More specifically, Section 14 recognizes that: "Advanced Metering Infrastructure is a critical component of a number of important aspects of the Clean Energy Initiative. The parties believe that AMI will help customers manage their energy use more effectively." HCEI Agreement at 24. In addition, Section 14 states that, "Unless the Commission identifies a compelling reason to do otherwise, all customers having advanced meters will be given the utility time-of-use or dynamic rate options and shall have to affirmatively opt out of the rate option." Id. Thus, Section 14 provides that

"AMI will be implemented as quickly as possible, along with proposals for time-of-use rates and customer electricity pricing information that facilitate substantive customer understanding and energy use management." Id. at 25.

A number of other sections of the HCEI Agreement also address technologies enabled or supported by AMI, as well as other AMI-related issues. For example:

- With respect to "The Solar Opportunity" and "Net Energy Metering," Sections 4 and 19 require new net metered installations to incorporate time-of-use metering equipment. See HCEI Agreement at 12, 28;

- With respect to "Greening Transporation," Section 10 contemplates the use of plug-in hybrid vehicles ("PHEVs") that will charge from the grid and run most of the time on electricity. See HCEI Agreement at 19;

- With respect to "Demand Response Programs," Section 13 provides that "[t]he Hawaiian Electric utilities will explore enabling technologies, and if appropriate, will add them to the system to make it easier for customers to receive energy pricing or event information and change or manage their energy use based on this new information." HCEI Agreement at 24;

- With respect to "Pricing Principles and Programs," Section 15 provides that "the utilities will complete the implementation of mandatory time-of-use rates to commercial and industrial customers by class as AMI is implemented. Demand response options, parallel with AMI deployment, will be offered to all C&I customers." HCEI Agreement at 26;

- With respect to "Meeting the Military's Needs, Section 16 identifies Advanced Metering as a mechanism for accomplishing that goal. See HCEI Agreement at 25;

- With respect to "The Smart Grid," Section 26 contains an agreement in principle acknowledging that a "smart grid" is a critical component of Hawaii's energy future" that will build "upon existing utility generation, transmission and distribution, using automation, communications, analytics and controls to operate the grid more efficiently, reliably, and safely, and improve the integration and use of intermittent renewables, demand-side and decentralized resources." HCEI Agreement at 31;

- With respect to the "Clean Energy Infrastructure Surcharge" ("CEIS"), Section 29 provides that "[t]he reasonable costs of infrastructure investments will be eligible for cost recovery through the CEIS if it can be demonstrated that the investments facilitate greater grid efficiency as determined and approved by the Commission, such as advanced meters and grid automation," HCEI Agreement at 34;

- With respect to "Greenhouse Gas ("GHG") Issues," Section 35 provides that "[t]he State shall support and expedite approvals of necessary infrastructure and rate structures, including smart metering, which enable and accelerate measures designed to reduce GHG emissions[.]" HCEI Agreement at 42; and
- With respect to "Telling the Energy Story," Section 36 provides that "[m]aintaining and upgrading the electric grid is essential to supporting reliable, renewable energy and to using technologies (such as advanced metering) that give customer options for better managing energy use." HCEI Agreement at 43.

Accordingly, an AMI system will support the HCEI Agreement by empowering customers to be use electricity wisely – both in terms of consumption and time of use – and also by enabling or facilitating the use of new technologies, such as Smart Grid technology, which will help to maintain the reliability of the Companies' systems as they endeavor to accommodate increasing amounts of intermittent renewable energy.[51]

2. <u>United States Congress: EPAct 2005, EISA & EESA</u>

AMI metering capabilities are being driven in part by federal energy policies such as EPAct 2005, EISA and EESA.

a. <u>Smart Metering: EPAct 2005</u>

EPAct 2005 renewed and expanded the federal government's practice of requiring that state regulators consider the adoption of certain ratemaking standards. Of particular relevance to AMI, EPAct 2005 established as a matter of federal policy that "time-based

[51] "An extensive review of demand response programs and their conservation effect, which we define as the change in total monthly or annual energy consumption attributable to the program, shows that although the primary intended effect of demand response programs is to reduce electricity use during times of peak load, the vast majority of demand response programs also yields a small conservation effect." Chris King and Dan Delurey, Efficiency and Demand Response: Twins, Siblings or Cousins?, Public Utilities Fortnightly, March 2005.

pricing and other forms of demand response . . . shall be encouraged."[52] Thus, Congress required regulatory commissions to consider adopting a "smart metering" standard[53] and specifically identified in EPAct 2005 several types of time-based ratemaking schedules including (1) TOU pricing,[54] (2) critical peak pricing ("CPP"),[55] (3) real time pricing ("RTP")[56] and (4) "credits for customers with large loads who enter into pre-established peak load reduction agreements that reduce a utility's planned capacity obligations."[57]

Time-based rates can send more accurate price signals to customers. Prices can be designed to be higher at the peak period of a day, season or other timeframe. In the short- and medium-term, these price signals provide incentives to customers to shift their electricity usage to low-priced periods and, symmetrically, to reduce their usage in high-priced periods. In the longer term, customers have incentives to engage in energy efficiency efforts focused on high-priced periods. Thus, appropriately designed time-based rate structures coupled with new smart meters can improve efficiency in electricity

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[52] PURPA § 132(f).

[53] As set forth in PURPA § 111(d)(14), the standard provides:

> TIME-BASED METERING AND COMMUNICATIONS.—(A) Not later than 18 months after the date of enactment of this paragraph, each electric utility shall offer each of its customer classes, and provide individual customers upon customer request, a time-based rate schedule under which the rate charged by the electric utility varies during different time periods and reflects the variance, if any, in the utility's costs of generating and purchasing electricity at the wholesale level. The time-based rate schedule shall enable the electric consumer to manage energy use and cost through advanced metering and communications technology.

[54] PURPA § 111(d)(14)(B)(i) defines traditional TOU as:

> [E]lectricity prices . . . set for a specific time period on an advance or forward basis, typically not changing more often than twice a year, based on the utility's cost of generating and/or purchasing such electricity at the wholesale level for the benefit of the consumer. Prices paid for energy consumed during these periods shall be pre-established and known to consumers in advance of such consumption, allowing them to vary their demand and usage in response to such prices and manage their energy costs by shifting usage to a lower cost period or reducing their consumption overall.

[55] PURPA §111(d)(14)(B)(ii) defines CPP as when "time-of-use prices are in effect except for certain peak days, when prices may reflect the costs of generating and/or purchasing electricity at the wholesale level and when consumers may receive additional discounts for reducing peak period energy consumption."

[56] PURPA § 111(d)(14)(B)(iii) defines RTP as "electricity prices . . . set for a specific time period on an advanced or forward basis, reflecting the utility's cost of generating and/or purchasing electricity at the wholesale level, and may change as often as hourly."

[57] PURPA § 111(d)(14)(B)(iv).

consumption, create an opportunity for regulators to support or offset cross-subsidies, and reduce the cost of improving system reliability.[58]

b. Smart Grid: EISA 2007

Enacted two years after EPAct 2005, EISA promotes energy independence and national security through provisions designed to increase energy efficiency and the availability of renewable energy.[59] Like EPAct 2005's smart metering provisions, the "Smart Grid" provisions set forth in Title XIII of EISA are instructive as to AMI implementation.

The Smart Grid opens new vistas when it comes to dealing with tomorrow's customers who will be born into the digital age.[60] Smart Grid technologies include a variety of operational and energy measures including smart meters, smart appliances, renewable energy resources, and energy efficiency resources that combine to create distribution systems allowing information to flow in two directions: (1) inside the house to thermostats, appliances, and other devices; and (2) from the house back to the utility.[61] As a result, Smart Grids benefit utilities and their customers by enabling appliances to be turned off during periods of high electrical demand and cost; giving customers real-time information on changes in electric rates; increasing power grid efficiency, reliability, and

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[58] See Kenneth Gordon, Wayne P. Olson, and Amparo D. Neito, Responding to EPAct 2005: Looking at Smart Meters for Electricity, Time-Based Rate Structures, and Net Metering, Edison Electric Institute (May 2006) ("EPAct Paper") at 13. EPAct 2005 also required state regulators to consider adopting a net metering standard.[58] Net metering allows the electric meters of customers with generating facilities to run backwards when their generator is producing more electricity than they demand themselves. Id. at 27-28.

[59] See generally Congressional Research Service Report for Congress, Energy Independence and Security Act of 2007: A Summary of Major Provisions (December 31, 2007) ("EISA Summary").

[60] Ahmad F. Faruqui, Ph.D., Will the Smart Grid Promote Smart Customer Decisions?, Presentation on behalf of The Brattle Group, June 19, 2008.

[61] See Congressional Research Service Report for Congress, Smart Grid Provisions in H.R. 6, 110th Congress (Updated December 20, 2007) ("Smart Grid Report") at 3.

flexibility; and reducing the rate at which additional electric utility infrastructure needs to be built.[62]

EISA contains a number of provisions intended to encourage research, development, and deployment of Smart Grid technologies. Perhaps most significantly to AMI, EISA § 1307 requires states to encourage utilities to employ Smart Grid technology and consider allowing utilities to recover Smart Grid investments through rates. Section 1307 accomplishes this by amending PURPA Section 111(d) so as to direct states to consider: (1) requiring electric utilities to consider "an investment in a qualified Smart Grid system" "prior to undertaking investments in non-advanced grid technologies . . . .";[63] (2) authorizing electric utilities "to recover from ratepayers any capital, operating expenditure, or other costs of the electric utility relating to the deployment of a qualified Smart Grid system, including a reasonable rate of return on the capital expenditures of the electric utility for the deployment of the qualified Smart Grid system"; and (3) "authorizing any electric utility . . . to recover <u>in a timely manner</u> the remaining book-value costs of any equipment rendered obsolete by the deployment of the qualified Smart Grid system, based on the remaining depreciable life of the obsolete equipment." EISA § 1307(a) (emphasis added).

New empirical evidence from a number of pilots shows that in-premise displays and similar devices that are enabled by the Smart Grid can lower energy use by up to 6%.[64] Some of the larger installations of Smart Grid technologies include installations by

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[62] <u>See</u> <u>id.</u> at 2.
[63] In considering Smart Grid technologies, Section 1307 directs electric utilities to consider certain appropriate factors, including total costs, cost-effectiveness, improved reliability, security, system performance and societal benefit. <u>See</u> EISA § 1307(a).
[64] Ahmad F. Faruqui, Ph.D., <u>Will the Smart Grid Promote Smart Customer Decisions?</u>, Presentation on behalf of The Brattle Group, June 19, 2008.

Southern California Edison Company, the Pacific Northwest National Laboratory ("PNNL") and TXU Electric Delivery Company.[65]

Recent Smart Grid and smart metering projects include ongoing or proposed installations by Duke Energy Indiana, Commonwealth Edison, Wisconsin Power & Light Company, Pacific Gas & Electric Company, Baltimore Gas & Electric Company, Public Service Electric & Gas Company, Pepco Holdings and Oncor Electric Delivery Company.[66]

c. Economic Stabilization: EESA 2008

The Emergency Economic Stabilization Act of 2008 ("EESA") created and amended a number of key tax provisions for the electric industry, some of which are particularly relevant to AMI technologies. For example, EESA created a reduced depreciation period for Smart Meters and Smart Grid assets which allows taxpayers to recover the cost of smart electric meters and smart electric grid systems over a 10-year period (instead of a 20-year period), while providing a positive exception for property that already qualifies for a recovery period shorter than 10 years.

In addition, EESA establishes a new credit for plug-in electric drive vehicles. The base amount of the credit is $2,500, plus another $417 for each kWh of traction battery capacity in excess of 4 kWh, with a cap. Further, EESA contains various provisions regarding credits and deductions related to energy-efficient homes, commercial buildings and appliances.[67]

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[65] See id. at 3-6. PNNL has been involved in Smart Grid demonstration projects with utilities such as the Bonneville Power Administration, PacifiCorp, Portland General Electric, Mason County PUD #3, Clallam County PUD, and the City of Port Angeles, Washington. See id. at 5-6.

[66] See Holly Fox, Power Companies Pitch 'Smarter' Savings, Medill Reports Chicago, May 28 2008; Rebecca Smith, Consumers, A Little Knowledge…, WALL ST. J., June 30, 2008, at R4.

[67] See Edison Electric Institute's summary, titled Emergency Economic Stabilization Act of 2008, KEY TAX PROVISIONS FOR THE ELECTRIC INDUSTRY (October 7, 2008). Other key EESA provisions

3. NARUC Resolution to Remove Barriers to AMI

The implementation of AMI has also been supported by NARUC, which, on February 21, 2007, adopted a "Resolution to Remove Regulatory Barriers To the Broad Implementation of Advanced Metering Infrastructure." In the NARUC Resolution, NARUC found, among other things, that:

- The implementation of dynamic pricing, which is facilitated by AMI, can afford consumers the opportunity to better manage their energy consumption and electricity costs through the practice of demand response strategies;
- Effective price-responsive demand requires not only deployment of AMI to a material portion of a utility's load, but also implementation of dynamic price structures that reveal to consumers the value of controlling their consumption at specific times;
- AMI deployment offers numerous potential benefits to consumers, both participants and non-participants, including:
  - greater customer control over consumption and electric bills;
  - improved metering accuracy and customer service;
  - potential for reduced prices during peak periods for all consumers;
  - reduced price volatility;
  - reduced outage duration; and,
  - expedited service initiation and restoration;
- The use of AMI may afford significant utility operational cost savings and other benefits, including:
  - automation of meter reading;
  - outage detection;
  - remote connection/disconnection;
  - reduced energy theft;
  - improved outage restoration;
  - improved load research;

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include an extension of the placed-in-service date for the Renewable Energy Production Tax Credit by one year; extension of the 30% Energy Tax Credit for solar and qualified fuel cell property to facilities placed in service through 2016; investment tax credits for the creation of advanced coal electricity and coal gasification projects; extensions and modifications to the energy Research and Development credit; extension of a provision allowing expensing of brownfield cleanup costs; and credits for the capture of CO_2. See id.

- more optimal transformer sizing;
- reduced demand during times of system stress;
- decreased T&D system congestion; and,
- reduced reliance on inefficient peaking generators;

- Sound AMI planning and deployment requires the identification and consideration of tangible and intangible costs and benefits to a utility system and its customers;
- Cost-effective AMI may be a critical component of the intelligent grid of the future that will provide many benefits to utilities and consumers; and
- It is important that AMI allow the free and unimpeded flow and exchange of data and communications to empower the greatest range of technology and customer options to be deployed.[68]

4. FERC

Although Hawaii is not under FERC's jurisdiction with respect to AMI, AMI implementation will help further FERC's stated objective of increasing transmission infrastructure for renewable energy. Electric utilities across the United States are faced with the need to add infrastructure for the transmission of electrical energy and particularly, for renewable electrical energy. Noting that there is "abundant evidence" of the need for new transmission facilities, FERC recently amended its regulations to establish incentive-based (including performance-based) rate treatments for the transmission of electric energy in interstate commerce by public utilities for the purpose of benefiting consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion. See Order 679 para. 14.

FERC has further observed that, to a degree, DR (which is supported by AMI) can serve as a substitute for generation and transmission. As a substitute for generation, DR can serve as a local peaking resource and thereby assist resource adequacy. As a substitute for transmission and distribution infrastructure, DR can reduce the need for

[68] See id.

new transmission or distribution expansion to bring generation to a local area. At minimum, DR can provide relief for an overloaded transmission system, and can defer the need for infrastructure.[69]

Consistent with FERC's position, the Pacific Economics Group has observed that, "In distribution, investment is needed to replace aging facilities, maintain or improve reliability, and serve growing demand. Advanced metering technologies can cut costs and facilitate the implementation of demand-response programs that permit economies in new capacity."[70]

D. AMI BENEFITS

As touched on above, AMI systems can provide numerous benefits (both quantifiable and intangible) for all stakeholders – customers, shareholders, and regulators.[71] The benefits of AMI can generally be broken down into two types: (1) operational benefits directly attributable to the AMI system; and (2) customer and system benefits derived from programs that the AMI system supports or provides a platform for developing (e.g., DR, distribution asset utilization and outage management), which give customers increased flexibility and satisfaction while empowering them to make wiser energy choices.[72]

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[69] See FERC Staff Report at Summary, page x.

[70] Mark Newton Lowry, PhD, Alternative Regulation of New Power Industry Investments, Pacific Economics Group, January 9, 2007.

[71] A table generally outlining the benefits of AMI is provided as Exhibit 15.

[72] See Joint Testimony of Portland Gen. Elec. Co. ("PGE") and Or. Pub. Util. Comm'n ("Oregon PUC") in Support of the AMI Stipulation, UE 189/Joint/100 Schwartz – Owings – Tooman (November 21, 2007) ("PGE Joint Testimony") at 7; see also FERC Staff Report at 18, stating that:

> The need to bill customers for their electricity consumption has historically been the primary reason to read electric meters. Today, with advances in metering technology and communication systems, advanced meters and infrastructure can provide additional value to utilities by enhancing customer service, reducing theft, improving load forecasting, monitoring power quality, managing outages, and supporting price responsive demand response programs.

1. Direct Operational Benefits

AMI implementation can significantly reduce meter reading and field services expenses, and can also increase the accuracy and timeliness of meter reading and billing.[73] For purposes of this Application, the Companies expect to realize direct and presently quantifiable, incremental AMI benefits arising from: (a) reduced labor expenses; (b) meter accuracy gains; and (c) energy theft recovery. These benefits are quantified in Section X below.

a. Labor Savings

For the Companies, the largest direct and presently quantifiable financial benefit of AMI will stem from labor and related expense savings associated with the reduction/elimination of many Field Services and Meter Reading functions. Activities currently performed by employees in these positions include manual meter reading, credit-related disconnections/reconnections, closing bill disconnections and new customer on premises ("NCOP") reconnections, meter unlocks for new customers, closing bill reads and meter re-reads.

Currently, non-AMI residential meters require the Companies to dispatch meter readers monthly to manually retrieve meter readings for monthly billing. In addition to the monthly dispatches, situations like the closing of an account or the need to revalidate an unusual meter recording currently require the Companies to dispatch a field service representative to manually read non-AMI residential meters. Once deployed, AMI meters will eliminate the need for such manual meter reading dispatches in the areas covered by the AMI Network. Disconnection and reconnection of service (due to service termination, new service, credit-related disconnection/reconnection of service, etc.) are

[73] See FERC Staff Report at 35.

other manual functions requiring the deployment of a field service representative that can be eliminated at customer premises equipped with AMI meters with remote disconnects.

As recognized by the Edison Electric Institute ("EEI"), the original and clearest motive for automated meter reading has been to reduce or eliminate the labor expense of manual meter reading while improving the accuracy and completeness of monthly billing.[74] An AMI communication network can exchange data with meters and virtually eliminate the need for any utility employee or utility contractor to access the meters on a monthly basis for meter reading. Customer benefits related to these types of capabilities include increased customer security, minimized billing anomalies (e.g., misreads, estimated reads, etc.), virtually eliminated meter access issues and immediate response to high bill inquiries.[75] EEI has further observed that, "When the vehicle, training, health insurance, and other overhead expenses of manual reading are included, reducing or eliminating manual reading is often the largest single AMI benefit."[76]

Moreover, AMI coupled with remote service connection/disconnection ("SCD") allows the utility to remotely disconnect customers. This enables the utility to disconnect service for a departing customer, thereby lessening disagreements over departing/arriving customer energy use. In addition, AMI enables a utility to turn on service for a new customer virtually in real time rather than forcing the customer to wait for a field service

[74] See EEI, Deciding on "Smart" Meters: The Technology Implications of Section 1252 of the Energy Policy Act of 2005, September 2006 ("EEI Smart Meter Article") at 16. The operational savings typically associated with remote meter reading include: (1) elimination of the need for meter-readers to read meters; (2) facilitation of more frequent meter reading; (3) elimination of problems associated with estimated bills; and (4) improved meter reading accuracy leading to reduced meter disputes. See NRRI Paper at 15.

[75] See Delmarva Power and Light Co.'s Blueprint for the Future Plan filed February 6, 2007 in Public Service Commission of the State of Delaware Docket No. 07-28 ("Delmarva Blueprint") at 46.

[76] See EEI Smart Meter Article at 16. "As a corollary to this, a utility can make a very quick and coarse estimate of the AMI benefits by multiplying by about 2.5 the total cost of its meter reading activity. Note that this estimates the benefit in traditional utility operations only. Other benefits are additional, such as demand response." Id., n.4.

crew to perform the task. This increases customer satisfaction while reducing utility dispatch costs, especially for locations with high levels of SCD activity.[77]

Similarly, AMI can reduce service calls and outages attributable to a customer-based outage event such as a circuit breaker opening during a storm. Customers often assume that the problem is utility-based and the normal process is for the utility to dispatch a field crew. Conceptually, an AMI system could be used for a real time meter service audit to determine if power is being supplied, and if the meter is operational and has not lost supply to a meter leg. In these events, the service can be restored in minutes without the need or expense of a field crew visit.[78]

b. Meter Accuracy Gains

An AMI system improves the accuracy of meter readings and, thereby, the calculation of all customer bills.[79] Meter accuracy tests[80] conducted by HECO indicate that the electromechanical ("EM") meters currently used by HECO's residential customers tend, on average, to under-record the energy passing through them by 0.4%. Tests conducted on the Sensus AMI meters, by contrast, indicate that the Companies' AMI meters will not under-record electricity usage. As a result, the Companies estimate that the AMI Project will yield meter accuracy gains equal to approximately 0.4% of the Companies' residential sales.

AMI enables other meter accuracy benefits as well, though not quantified. For example, an AMI system includes numerous processes[81] to verify that a meter is recording properly, thus enabling the automated discovery of malfunctioning meters.

[77] See Delmarva Blueprint at 48.
[78] See Delmarva Blueprint at 48.
[79] See Delmarva Blueprint at 46.
[80] The meter accuracy test report is shown as Exhibit 16.
[81] Meter firmware, RNI, and MDMS work collectively.

The AMI system software is designed to detect certain meter and communication malfunctions that can be directly reported to the utility.[82] Accordingly, AMI should result in the additional intangible benefit of greater customer and utility confidence in meter accuracy.

c. Energy Theft Recovery

Electricity theft is an issue that universally plagues all utilities. Besides the fact that electricity theft is a crime, it also creates an undue burden for ratepayers, to whom the cost associated with stolen energy and associated revenue protection programs is often passed. The Companies estimate the AMI Project will provide ratepayer benefits, in the form of energy theft recovery, equal to approximately 0.14% of the revenues recorded by the replaced meters.[83]

AMI systems are designed to support revenue assurance and minimize meter tampering. The "infrastructure" in an AMI system includes information systems that are capable of processing large amounts of interval data. Many forms of meter bypass (i.e., taps) are clever and very well concealed. For example, an underground tap ahead of a meter may be buried or otherwise inaccessible in ductwork or raceways.[84] The interval

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[82] See Delmarva Blueprint at 46.

[83] In calculating the percentage of energy theft expected to be reduced by AMI, the Companies surveyed studies conducted by the Electric Power Research Inst. ("EPRI"), San Diego Gas & Elec. Co. ("SDG&E"), Southern California Edison ("SCE"), Duke Power Co. and Dominion Resources Inc. Combining the results of these studies, the Companies expect that they will be able to recover approximately 20-30% of the revenues lost from energy theft, which according to the studies, generally ranges from 0.25-1.0 % of sales revenues. As further detailed in Exhibit 17 attached hereto, the 0.14% figure used by the Companies is based on a midpoint analysis of the recoverable revenue percentages derived from the surveyed studies.

[84] See EPRI Final Technical Report titled Revenue Metering Loss Assessment (November 2001) at xi. According to EPRI, "It is obviously both uneconomic and technically impossible to isolate and correct every problem. Accordingly, filed data on incidents of energy theft and metering anomalies will always understate the full extent of the problem." Id.

data from AMI is useful in detecting anomalous patterns of energy use exhibited by some of the major methods of tampering, which are otherwise difficult or expensive to detect.[85]

In addition to facilitating tampering detection, AMI reduces energy theft through the use of meters that are more difficult to tamper with than conventional meters. For example, an AMI meter does not have a spinning disc that can be slowed down. Moreover, AMI enables the detection of inverted meters[86] through the daily collection of hourly data and built-in tamper detection.[87]

2. Customer and System Benefits

In addition to reducing operational costs, many of the functionalities that AMI makes possible also improve the quality of service provided to customers. An AMI system can be likened to the purchase of a complete computer operating system and some software. The computer has some functionality, but also has great potential for additional benefits as the owner purchases or develops new software.[88]

Likewise, the customer and system benefits of the Company's AMI Project have the potential to produce significant cost savings in the future, but will also require additional costs and investment to implement.[89] Converting many of these benefits into dollar values would require many assumptions about future energy prices, emerging

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[85] See Delmarva Blueprint at 48; Re Application of San Diego Gas & Elec. Co. (U-902-E), Cal. Pub. Util. Comm'n Application 05-03-015, Rebuttal Testimony of James Teeter, San Diego Gas & Elec. Testimony, (September 7, 2006) at JT-3 thru -4.
[86] Electromechanical meters will run backwards when placed in an inverted position in the socket, whereas new AMI meters can detect this and properly register electricity usage.
[87] See Delmarva Blueprint at 48; Re Application of San Diego Gas & Elec. Co. (U-902-E), Cal. Pub. Util. Comm'n Application 05-03-015, Rebuttal Testimony of James Teeter, San Diego Gas & Elec. Testimony, (September 7, 2006) at JT-3 thru -4.
[88] See Direct Testimony of Portland Gen. Elec. Co., Advanced Metering Infrastructure, UE 180/PGE/800 Hawke – Carpenter – Tooman (March 15, 2006) ("PGE Direct Testimony") at 7.
[89] See PGE Joint Testimony at 7.

technologies and the market in general. Thus, as explained above, a number of intangible benefits associated with AMI have not been quantified for purposes of this Application.

In the future, the Companies expect the AMI Project to enable additional benefits derived from programs that the AMI system will support or provide a platform for developing. These benefits include: (a) empowering customers to make smart energy choices, (b) improved customer service, (c) improved distribution planning and engineering, and (d) improved outage management.

a. Empowering Customers to Make Smart Energy Choices

An AMI system empowers customers to be proactive in their utilization of electricity, both in terms of consumption (energy) and time of use (demand).[90] Specifically, AMI enables customers to make smart energy choices by: (i) providing customers with access to their usage information; (ii) facilitating the implementation of DR technologies; (iii) allowing utilities to utilize time variable pricing options; and (iv) supporting other rate options and/or any of a number of future benefits that have yet to be developed in connection with emerging AMI-related technologies.[91]

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[90] See Chris King and Dan Delurey, Efficiency and Demand Response: Twins, Siblings or Cousins?, Public Utilities Fortnightly, March 2005:
Our review shows that demand response programs usually result in a small reduction in total electricity consumption in addition to a much larger reduction in electricity use during peak hours. The average reduction ranges from about 4 percent for dynamic pricing programs, to a fraction of a percent for reliability programs, to around 10 percent for effective information/feedback programs. These averages mask important variations, namely that some dynamic-pricing programs result in no observed reduction in consumption (and in one case apparently led to an increase). With respect to the different types of programs, the conservation effect appears to be largely additive.

[91] See Freeman Sullivan, Characterizing and Quantifying the Societal Benefits Attributable to Smart Metering Investments, Electric Power Research Institute Topical Report, July 2008 ("EPRI Report"). The EPRI Report characterizes the potential societal benefits of AMI as follows:

1. Service quality enhancements that may reduce the duration of outages;
2. Feedback made available to consumers about electricity consumption in an actionable and timely fashion that may result in reduced electricity consumption and bill savings;
3. Demand response programs that provide consumers with inducements to modify their electricity consumption through price or other incentives, thus providing them with a opportunity to reduce their electricity costs;

i. Customer-Access to Usage Information

AMI enables utilities to help their customers control energy costs in ways as simple as showing customers, on their monthly billing statements, when they use energy. An AMI system's ability to collect interval data on a daily basis creates a rich and valuable database. This database, in conjunction with an interactive portal or other device, enables customers to readily determine how and when they use energy and, in turn, to develop strategies for lowering their bills.[92]

In addition, more frequent meter-reading will allow customers to track their changing usage and electricity costs, making it easier for customers to budget for such costs. Similarly, by eliminating the need for estimated bills, AMI makes it possible for customers to have timely and accurate readings of their actual usage, and receive bills that do not require adjustment. This accuracy helps with electricity cost budgeting. Estimated bills also create billing disputes that are not only costly to the utility, but aggravating and time-consuming for customers. As a result, more timely and accurate meter readings should also serve to remove a common source of distrust by consumers toward utilities.[93]

ii. Demand Response

The demand management benefits of AMI have been widely discussed in public forums since the rolling blackouts in California in 2000. The term "demand response" has come

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4. New products and services that can create opportunities to use electricity more efficiently and effectively;
5. Reduction of externalities, which are potentially adverse impacts of electricity usage on the environment or society that are not explicitly reflected in electricity prices but whose reduction benefits all consumers; and
6. Macroeconomic benefits may arise from changes in the expenditure patterns of utilities and consumers that can enhance regional employment and raise wages.

EPRI Report at viii.

[92] See Delmarva Blueprint at 46-47.

[93] See NRRI Paper at 16.

to mean actions by energy users in response to electric market dynamics. The principal economic benefit of DR is that, during periods of high energy demand, a small reduction in demand produces a relatively large reduction in marginal cost.[94] As stated by EEI, price and demand reductions during high-demand periods benefit the utility in many ways, including: reduced peak capacity requirements; improved electrical system efficiency (from lower operating costs) and reliability (from lower maintenance costs); and greatly facilitated settlement data management.[95]

AMI systems can support DR technology, such as remotely controllable programmable thermostats, to directly reduce customer electricity demand during periods of high electricity demand.[96] Similarly, AMI could be used to enhance the integration of a utility's DR and energy efficiency portfolios as part of an integrated demand side management portfolio.[97]

iii. Time Variable Pricing Options

AMI also supports DR through time variable pricing options that more closely track electricity supply conditions. Time-based rate structures charge utility customers different prices for consumption at different times of the day, based on differing underlying costs. Time-based rate structures can improve the accuracy of the price signals that customers face during any time interval, thereby giving customers an

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[94] See EEI Smart Meter Article at 17.
[95] See EEI Smart Meter Article at 18.
[96] See Delmarva Blueprint at 47.
[97] See Opening Brief of San Diego Gas & Elec. Co., filed October 27, 2006 in A.05-03-015:

> AMI deployment will also enhance the integration of SDG&E's Energy Efficiency and DR program portfolios. . . . Energy Efficiency and DR programs are part of an integrated demand side management portfolio, which includes programs such as peak load management and A/C cycling. SDG&E does not intend to abandon these programs. As witness Gaines testified, "[t]hese programs . . . achieve both energy efficiency and demand response … "and SDG&E will continue our efforts on these exact same programs."

incentive to reduce their electricity usage during high-cost periods, and shift it to low-cost periods. Accordingly, AMI-enabled time variable rate options can benefit both customers and society.[98]

Examples of rate options that directly reflect existing electricity market conditions include dynamic pricing, TOU rates, CPP, RTP and critical peak load reduction rebates. Participants in these rate options can reduce their monthly electricity bills by reducing their electricity consumption during high priced periods and thereby place significant downward pressure on energy and capacity prices – benefiting all of a utility's customers. These rate options, when combined with the availability of direct load control technology can be a powerful tool for reducing overall peak electricity demand in a customer friendly manner.[99]

HECO's DPP Pilot Program

Pursuant to the Commission's Framework for Integrated Resource Planning ("IRP Framework"),[100] HECO filed its application requesting approval of a DPP Program and recovery of program costs on April 24, 2008 ("DPP Application").[101] HECO's DPP Program is a DR program that provides peak time customer incentives, or rebates ("PTR"). A PTR program provides monetary incentives to customers for every kWh saved during the applicable time period. HECO's DPP Program will involve the active participation of about 600 pilot program test participants that will be eligible for PTR

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[98] See Delmarva Blueprint at 47; EPAct Paper at 2. When prices reflect short-run marginal costs, such shifts in market behavior can increase the overall efficiency of the electric system on both the demand and the supply sides. The net benefits to society from these efficiency improvements include: (1) the consequences of the change in the utility's investment decisions and the corresponding reduction in operating costs; and (2) the changes in the purchasing behavior of consumers. Correct price signals benefit customers and society. See id.

[99] See Delmarva Blueprint at 47; EPAct Paper at 2.

[100] See Paras. II.B.7, III.F, and V of the IRP Framework, issued pursuant to Decision and Order No. 11523 (March 12, 1992) and Decision and Order No. 11630 (May 22, 1992), in Docket No. 6617.

[101] See Docket No. 2008-0074.

rebates of $1 for every kWh saved, and the monitoring of the energy use of about 400 customers in a control group that will not be eligible for rebates.[102]

One of the stated objectives of HECO's DPP Program is to "[v]alidate the ability of AMI meters to collect and transmit accurate time-based energy consumption information to the Company's billing system."[103] Accordingly, HECO indicated in its DPP Application that its installation of AMI meters will commence after the recruitment of DPP Program participants is completed in order to derive the amount of kWh saved under the DPP Program and also to collect information used in that derivation.[104] HECO is awaiting the Commission's approval of its DPP Application before it recruits program participants.[105]

iv. Support of Other Rate Options

AMI technologies can support other emerging technologies and rate options such as pricing tariffs that reward renewable generators for their production of electricity during periods of high energy prices. This is particularly valuable for resources such as photovoltaic ("PV") systems, which supply energy during the day. In addition, AMI can provide remote monitoring of the output of a utility's distributed generators.

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[102] See DPP Application at 7. There would be a maximum of 10 critical peak periods, no more than 6 hours long for each period, during the pilot. Energy use data from 10 critical peak periods are expected to provide sufficient information to permit statistically robust inferences from the one-year pilot program. Id. at 8.

[103] DPP Application at 12.

[104] See DPP Application at 9-10.

[105] The last activity in the DPP Application, Docket No. 2008-0074, is that HECO submitted its responses to CA-IR-1 to 25, filed on July 18, 2008.

Plug-in Electric Vehicles

AMI could also enable rate designs to support the off-peak charging of plug-in hybrid electric vehicles[106] ("PHEVs"). Recently, automakers, utilities and the public have become increasingly interested in PHEVs, which according to EPRI, "represent the most promising approach to introducing the significant use of electricity as transportation fuel." PHEVs add the ability to charge a hybrid vehicle's battery using low-cost, off-peak electricity from the grid – allowing a vehicle to run on the equivalent of 75¢ per gallon or better at today's U.S. mainland electricity prices, while drawing only about 1.4 to 2 kW of power while charging – approximately what a dishwasher draws.[107] Studies further indicate that the use of PHEVs would lead to significant GHG emission reductions.[108]

In addition to creating a cleaner and cheaper alternative to traditional automobile combustion engines, PHEVs can create benefits for the grid as well. With AMI-enabled off-peak charging, the grid could support a high level of PHEV penetration without the need for more generating capacity, thus improving power system efficiency (and ultimately benefiting ratepayers). Eventually, PHEVs might also be considered for use as home-based energy storage units for PV systems, or as a source of stored power that could be tapped as needed by the utility.[109]

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[106] See John Douglas, Plug-In Hybrids on the Horizon: Building a Business Case, Electric Power Research Institute, Spring 2008 ("EPRI PHEV article"); see also Delmarva Blueprint at 48.

[107] EPRI PHEV article at 8. A shift from gasoline to PHEVs could reduce the gasoline consumption by up to 6.5 MMBpd, which is equivalent to 52% of the U.S. petroleum imports. Michael Kintner-Meyer, Kevin Schneider & Robert Pratt, Impacts Assessment of Plug-In Hybrid Vehicles on Electric Utilities and Regional U.S. Power Grids Part 1: Technical Analysis, PNNL, November 2007 ("PHEV Technical Analysis") at 16.

[108] See EPRI PHEV article at 9; see also PHEV Technical Analysis at 16 ("There are potentially significant greenhouse gas emission impacts if the gasoline-based LDV fleet were to transition to a PHEV technology.").

[109] See EPRI PHEV article at 11-13.

b. **Improved Customer Service**

AMI provides enhanced customer service capabilities that are typically not available with manual meter reading or with AMR. These benefits include new or improved services that utilities can offer to customers in connection with interval data showing not only a customer's total usage for each day but also when the energy was used. The customer service benefits of AMI include: flexible billing cycles; the ability to readily obtain meter readings that coincide with customer requested move dates; improved utility response to high bill inquiries; benchmarking of energy usage; aggregation of accounts and/or synchronization of multiple account billing and meter reading; web services based on more timely information;[110] bill prediction for large and small customers (including weather forecast data); and rapid utility notification of customer outages.[111]

c. **Distribution Asset Utilization**

In addition to empowering customers, AMI can provide important information to assist in electric utility asset management. As noted by the FERC, the proper sizing of equipment, based on detailed and accurate data on customer demand and usage patterns can be a sizeable benefit for utilities. AMI provides information that can be used to model and optimize the benefits and risks of adding capacity to a utility's system, thereby optimizing the utility's capital expenditures.[112]

Another key asset management benefit provided by AMI relates to the ability of electric utilities to more efficiently monitor and maintain the distribution equipment

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[110] The timely processing of meter data can also improve a utility's cash flow because of the reduction in the time it takes the utility to produce a bill after the meter is read. FERC has stated that before advanced metering, the average time for read-to-bill date was three to five days, but that with advanced metering, this usually drops to one or two days. See FERC Staff Report at 37.
[111] See FERC Staff Report at 37; Delmarva Blueprint at 46.
[112] See FERC Staff Report at 36; Delmarva Blueprint at 46.

necessary to reliably deliver stable power to customers. As discussed above, Smart Grid concepts are now available which permit the utility to deploy an array of sensors and control devices supported by AMI systems to provide additional near real-time monitoring. Examples include transformer load management, feeder load analysis, recloser control, fault indicator monitoring, voltage and phase monitoring, and capacitor bank switch control for improved voltage stability. Moreover, interval data from AMI systems can be used to evaluate the impact of both energy efficiency and DR programs on the utility's system.[113]

d. Outage Management

AMI technologies can provide a number of outage management benefits as well. Outages, slow restoration times, and lack of good estimates regarding outage time can be a source of considerable frustration to customers. Thus, identifying outage locations, dispatching crews more efficiently, and restoring service to customers more rapidly can result in better outage metrics.[114]

AMI systems support more rapid customer restoration time as a result of their ability to detect outages without customer calls. This enables utilities to respond to outages as quickly as possible and often before the customer even knows an outage has occurred. AMI systems are also capable of tracking and reporting momentary outages that could indicate a loose conductor coupling, cracked conductor or other service issues such as a rubbing tree branch. Faster outage response capabilities and more accurate

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[113] See FERC Staff Report at 36; NRRI Paper at 17; Delmarva Blueprint at 46-47.
[114] See FERC Staff Report at 37; NRRI Paper at 16.

repair time estimates can improve customer service and reduce call center volumes during outages.[115]

In addition, AMI can enable a utility to verify an outage before dispatching field service personnel to respond to the outage by checking for power to customer meters. If the problem turns out to be on the customer side of the meter, the utility can achieve cost savings by not dispatching a repair crew unnecessarily, while in turn, the customer can begin effecting repairs sooner.[116]

Moreover, AMI enables outage repair crews to be dispatched with improved accuracy, and thus, in a more efficient manner. AMI data can enable a utility to acquire outage information within minutes of an event – permitting the utility to determine the type of repair likely to restore power most quickly to the greatest number of customers. Consequently, utilities can restore power faster, and often during regular hours, and customers are not faced with reporting the outage and then waiting for repairs to be made. Customer benefits from these capabilities include minimization of outage inconvenience, reduction in lost revenues and minimization of lost product.[117]

Further, after outage work crews finish their first round of repairs, utilities can use advanced metering on customer premises to check for additional problems before field service personnel leave the area. This eliminates the need to recall repair crews to fix problems not handled in the first round of repairs, while facilitating quicker restoration of power.[118]

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[115] See Delmarva Blueprint at 47; FERC Staff Report at 37.
[116] See FERC Staff Report at 37.
[117] See Delmarva Blueprint at 47.
[118] See FERC Staff Report at 37.

IX

PROJECT SCHEDULE

The AMI Project schedule for the HECO Companies is provided as Exhibit 18. Assuming that the AMI Project receives Commission approval by January 2010, HECO will begin developing and implementing the MDMS in January 2010, and expects that the initial phase (basic CIS and RNI integration) of the MDMS would be completed within one year, by January 2011. The second phase (additional integration tasks) and the third phase (customization work) of the MDMS are expected to be completed in December 2011 and November 2012, respectively. The details of each MDMS phase are shown below:

Phase I – Basic CIS and RNI Integration will provide full billing capability for existing rates and for additional TOU rates as required. In this phase, data from all the AMI meters will be routed from the RNI into the MDMS.

Phase II – Additional Integration Tasks to centralize more user functions within the MDMS and minimize actions that must be performed by users and system administrators manually or from within the RNI.

Phase III – Additional customization of the MDMS will be performed to redirect all <u>existing</u> Companies' metering systems (MVRS, MV90, and Turtle PLC) into the MDMS.

A. <u>HECO AMI SYSTEM</u>

The installation of the AMI Network on Oahu will follow an incremental approach beginning in November 2010 and progressing through August 2013. The HECO meter full-scale deployment period is planned to begin in May 2011 and end in December 2013.

B. MECO AMI SYSTEM

The installation of the AMI Network on Maui will follow an incremental approach beginning in November 2013 and progressing through September 2014. The MECO full-scale meter deployment period is planned to begin in April 2014 and end in December 2014.

C. HELCO AMI SYSTEM

The installation of the AMI Network on the island of Hawaii will follow an incremental approach beginning in October 2014 and progressing through August 2015. The HELCO full-scale meter deployment period is planned to begin in April 2015 and end in December 2015.

X

PROJECT COST AND BENEFITS

The AMI Project costs and off-setting benefits are described below for all three Companies. Shared software and hardware costs (such as for the MDMS and RNI) are allocated among each of the Companies based on customer count[119]. The accounting and ratemaking treatment of all costs in this section is described in Section XI.

The total cost of the AMI Project during the six-year deployment is estimated at $110,364,000[120] for all three Companies. This cost is composed of implementation costs ($97,938,000) and operating costs ($12,426,000). Costs for the individual Companies are summarized in Exhibit 19, Tables 1, 2, and 3, and further described below.

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[119] Customer count as of December 31, 2006. Of a total 434,342 customers, HECO, MECO and HELCO customer counts were 292,988, 64,937, and 76,417, respectively. This results in a cost share allocation of 67.4% for HECO, 15.0% for MECO, and 17.6% for HELCO.
[120] This figure includes capital, deferred, and expensed cost components.

A. PROJECT COSTS BY FUNCTION

AMI Project functions are divided into four major categories: (1) Project Management, (2) AMI Meters, (3) AMI Network, and (4) MDMS. Costs for each function are described below.

1. Project Management

The Companies' project management cost to oversee the development and implementation of the AMI Project totals $10,611,000. Exhibit 19, Table 4 summarizes these costs and shows the breakdown amongst the three Companies.

2. AMI Meters

Exhibit 19, Table 5 summarizes the meter cost of $74,900,000 for the AMI Project. The meter costs include costs for new AMI meters, installation costs, replacing damaged meter socket costs, and replacing damaged/failed AMI meter costs. AMI meter hardware costs are estimated at $48,749,000 for the project based on the AMI meter counts identified in Section I. The Companies' installation cost of $13,186,000 assumes the use of an outside vendor[121] for all residential meter installations and the Companies' workforce for the installation of all C&I meters. The replacement of sockets damaged during the removal of the non-AMI meter with an AMI meter will be expensed and estimated to cost $11,738,000 based on an estimated damage rate of 1% of all meter sockets encountered.

Though the new AMI meters come with a one year manufacturers' warranty towards hardware replacement costs, additional costs will be incurred for the replacement labor of those defective meters and for meters that fail beyond the one year warranty

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[121] The Companies will continue to evaluate whether a more cost-effective installation plan can be implemented using internal resources or a combination of resources.

period. For the 2010 through 2015 project period, $781,000 for the cost of replacement AMI meters plus $446,000 in labor is estimated for the replacement of AMI meters.

3. AMI Network

The AMI Network is described in Section VII. Its costs include AMI Network costs, costs for Sensus additional options, and FNP/FRP costs. The Companies will pay a monthly per endpoint fee to Sensus for the use of the AMI Network. The Companies will also pay Sensus to provide RNI tape backup service, RNI scalability testing, and a performance bond. To supplement the TGB coverage of the meters, the Companies will use FNPs and FRPs that will be purchased, installed, and maintained by the Companies. The FNP/FRP costs were estimated assuming that 20 FNP/FRPs[122] are required for the AMI Project deployment statewide. A summary of the AMI Network costs of $4,693,000 for 2010 through 2015 is listed in Exhibit 19, Table 6.

4. MDMS

Functionally, the MDMS costs can be grouped into: (1) hardware and operating system costs; (2) software development costs; (3) MDMS licensing fee costs; (4) training, process and change management costs; and (5) ongoing support and maintenance costs.

The MDMS hardware and operating system software costs of $1,524,000 will be capitalized. Phase I, II, and III deferred costs for software development are $6,302,000, $4,855,000, and $1,341,000, respectively. The one-time MDMS licensing fees, incurred as meters are installed and charged on a per meter basis, are estimated to be $1,042,000. MDMS training on the systems, process management related charges, and change management costs are estimated at $1,804,000. In addition, MDMS support and

[122] The specific quantities of FNP and FRP will be determined during deployment.

maintenance throughout 2015 is estimated at $3,292,000[123]. A summary of the MDMS costs by function is listed in Exhibit 19, Table 7.

MDMS costs grouped by computer software development accounting stages are summarized in Exhibit 19, Table 8.

B. PROJECT COSTS BY CAPITAL, DEFERRED, EXPENSE

Instead of by function, the total AMI Project costs of $110,364,000 from 2010 through 2015 can also be summarized as follows: (1) Capital Costs of $65,025,000; (2) Deferred Costs of $13,540,000; and Expense Costs - $31,799,00.

1. Capital Costs

Exhibit 19, Table 9 provides a summary of the $65,025,000 in AMI Project capital costs over the project implementation period (2010 through 2015). The capital costs for the Companies include $48,749,000 and $13,186,000 for the material and installation of new AMI meters, respectively; $781,000 and $446,000 for the damaged meter replacement material costs and installation, respectively; $1,524,000 for MDMS hardware and operating system costs (including AFUDC); and $339,000 for FNP and FRP materials and installation.

2. Deferred Costs

Exhibit 19, Table 10 summarizes the $13,540,000 of MDMS software development costs estimated to be incurred. These costs consist of licensing fees charged and allocated on a per meter basis, certain costs associated with the development of the MDMS Phases I, II, and III described in Section IX, and AFUDC on the deferred costs

[123] Support and maintenance costs of the MDMS, as well as AMI Network lease costs, are on-going costs that extend beyond the project period for as long as the AMI system is utilized.

during the deferral period. When approved, these costs will be deferred and amortized over a 12-year period.

3. <u>Expense Costs</u>

Exhibit 19, Table 11 summarizes the $31,799,000 in expenses to be incurred in connection with the AMI Project. Expenses include: $10,611,000 of project management costs; $11,738,000 of damaged meter socket replacement costs; $1,804,000 of MDMS training, process and change management; $3,292,000 of support and maintenance costs; and AMI Network costs consisting of $4,159,000 for the network lease and $195,000 for options.

C. <u>PROJECT BENEFITS</u>

Offsetting AMI Project costs are the quantifiable direct operational benefits of $25,514,000 for years 2010 through 2015 described in Section VIII. These benefits will be a result of: (a) a reduction in manual meter reading expense, (b) a reduction in field services expenses related to remote disconnect/reconnect and remote read capabilities, (c) reduced electricity theft, and (d) meter accuracy gains. See Exhibit 19 Table 12.

The estimated benefits are presented for the six year period of the project. However, these benefits, and other benefits not quantified, will continue well beyond the project years. Each AMI Project benefit is described below.

a. Meter reading savings currently represent the largest single quantifiable benefit associated with the AMI Project. AMI's automated meter reading capabilities will result in savings of $10,975,000 in the first six years due to labor and related expense savings related to the elimination of monthly manual meter reads.

b. AMI is expected to reduce field services expenses by $3,898,000 in the first six years by eliminating costs associated with the manual disconnection and reconnection of customers to the utility's system, and manual closing bill reads and meter re-reads.

c. Once fully installed, the Companies estimate that AMI will facilitate in the recovery of 0.14% of their total revenues, which are currently lost to energy theft. The Companies' incremental energy theft recovery benefits are estimated at $7,217,000 over the project period. The energy theft benefits are expected to be realized with the first deployment of AMI meters beginning in 2011 for HECO, and expected to grow as the rest of the Companies' AMI meters are installed and brought on line. The energy theft recovery benefit is expected to grow with the Companies' total revenues.

d. The Companies estimate that the AMI meters, which do not "slow down" over time as older non-AMI EM meters do (and therefore do not under-record the electricity delivered to customers), will result in a 0.4% enhancement of the Companies' variable residential electric sales revenue, estimated at $3,424,000 over the project period. The first meter accuracy benefits are expected to be realized with the initial deployment of AMI meters beginning in 2011 for HECO, and expected to grow as the rest of the Companies' AMI meters are installed and brought on line. Thereafter, meter accuracy benefits are expected to grow with the Companies' variable energy sales, until each respective Company's next rate case recalibrates such benefits back into base rates.

Exhibit 19, Table 12 provides a summary of these benefits.

XI

AMI SURCHARGE, ACCOUNTING AND COST RECOVERY

A. AMI COST RECOVERY

1. Recovery of AMI Costs through the REIP Surcharge

The Companies are requesting approval to recover all of the incremental costs associated with the AMI Project through the REIP Surcharge that is pending approval in Docket No. 2007-0416[124], or through an AMI Surcharge mechanism approved by the Commission in this proceeding if the REIP Surcharge is not available.

This is the approach agreed upon by the parties to the HCEI Agreement discussed above, which provides in relevant part that the meters and associated costs for the AMI Project will be paid for through the CEIS (i.e., the REIP Surcharge), until such costs are embedded and recovered in the utilities' base rates in future rate cases.

As the parties to Docket No. 2007-0416 (REIP proceeding) agreed in their letter filed November 28, 2008, the proposed REIP Surcharge is substantially similar to the CEIS included in the HCEI Agreement and the REIP Surcharge proposal currently pending Commission decision-making in Docket No. 2007-0416 satisfies the HCEI Agreement provision that the implementation procedure of the CEIS recovery mechanism be submitted for Commission approval by November 30, 2008. Therefore, recovery of incremental AMI costs through the REIP Surcharge would be consistent with the CEIS provisions in the HCEI Agreement.

[124] By letter dated and filed October 22, 2007, the parties to the REIP Docket Docket notified the Commission that they were in agreement on all issues, and that it is appropriate that the Commission approve the HECO Companies' proposed Renewable Energy Infrastructure Program ("REI Program") and related REIP Surcharge, as provided in Exhibit B to the HECO Companies' Reply Position Statement, filed September 17, 2008. The HECO Companies provided their proposed REIP Surcharge provision in their response to CA-SIR-1, filed July 11, 2008, and in Exhibit E to their Reply Position Statement. The status of the REIP Docket (Docket No. 2007-0416) is summarized in Exhibit 20 hereto.

Section II.B.1 of the proposed REIP Framework provides that electric utilities may recover the Capital Costs[125], deferred costs relating to software development and licenses, and/or other relevant costs approved by the Commission of REI Projects by means of the REIP Surcharge. Section III.B.1 of the REIP Framework.

REI Projects include infrastructure projects that encourage renewable choices and/or customer control to shift or conserve their energy use:

> Infrastructure projects and other projects can encourage renewable choices, facilitate conservation and efficient energy use, and/or otherwise allow customers to control their own energy use. For example, there are a variety of projects that could encourage renewable energy choices which include customer selection of renewable resources as well as allowing a customer to use less nonrenewable resources. Systems such as smart meters would allow customers to monitor their own consumption and use of electricity and allow for future time-based pricing programs. Systems such as automated appliance switching would provide an incentive to customers to allow a utility to mitigate sudden declines in power production inherent in as-available energy.

Section III.B.1.a.iii of the REIP Framework.

The proposed REIP Framework provides that costs eligible for the REIP Surcharge include:

> (i) allowed rate of return or other form of return mechanism (set in the last rate case of the utility where the Project is located) on the investment from the in-service date of the Project;
>
> (ii) depreciation (at a rate and methodology to be set forth in the Project's application) to begin the month after the in-service date of the Project;
>
> (iii) AFUDC, applicable taxes, and other capital and deferred expense related charges; and
>
> (iv) other relevant costs as approved by the Commission in an request for approval to include the costs of the Project in the REIP Surcharge.

[125] "Capital Costs" are defined to mean a project's return on investment and return of investment (i.e., depreciation).

Section III.B.3.b of the REIP Framework.

Similarly, Section 29 of the HCEI Agreement states that the CEIS is designed to expedite cost recovery for infrastructure that supports greater use of renewable energy or grid efficiency within the utility systems and specifies, among other things, the following:

1. The establishment of a CEIS to recover the reasonable costs of new transmission and other infrastructure investment needed to facilitate new clean energy investments by the utility or by IPPs. Subject to Commission approval, the CEIS may also be used to recover costs that would normally be expensed in the year incurred and may be used to accelerate cost recovery.

2. Capital costs eligible for recovery through the CEIS include the allowed return on investment based on the rate of return from the last rate case, AFUDC as appropriate, depreciation, applicable taxes, other costs as approved by the Commission.

3. The reasonable costs of infrastructure investments will be eligible for cost recovery through the CEIS if it can be demonstrated that the investments facilitate greater grid efficiency as determined and approved by the Commission, such as advanced meters and grid automation.

4. The reasonable costs of infrastructure investments that may be recovered through the CEIS, as determined by the Commission, include transmission lines built, in significant part, to facilitate renewable energy development, inter-connection equipment, advanced metering infrastructure, battery storage, and other equipment to facilitate increased use of renewable energy whether utility or third-party owned.

5. The CEIS may also be used to recover costs stranded by clean energy initiatives when approved by the Commission.

6. The CEIS is a mechanism to timely recover: (a) costs that would be expensed in the year incurred; and (b) a return on and of the costs of specific capital projects deemed necessary for the achievement of the HCEI objectives. The CEIS is not a financing vehicle for the Hawaiian Electric Companies.

HCEI Agreement at 34.

If AMI capital costs (e.g., return on and return of capital) are recovered through the REIP Surcharge, the proposed REIP Framework provides that such capital costs would be offset by the net benefits of implementing AMI (e.g., cost savings and revenue enhancements offset by O&M expenses), as those net benefits are obtained by the electric utility. Section III.B.3.c of the REIP Framework.

The Companies' incremental costs associated with the AMI Project include the estimated costs to the HECO Companies of installing or acquiring the AMI platform (i.e., the capital costs of the advanced meters, the capital, deferred and O&M costs for the MDMS system, and the O&M costs for the AMI Network), as offset by the O&M cost savings attributed to automating meter reading and certain field service activities, and the revenue enhancements from improved meter accuracy and reducing electricity theft. As addressed below, the net revenue requirement impacts of these costs and savings would be recovered through the REIP Surcharge.

The proposed REIP Framework provides that project details, including the period of recovery of the project's cost, appropriate depreciation amounts and other project details will be outlined in the request for approval to include the costs of the project in the REIP Surcharge. Section III.B.3.d of the REIP Framework. The required project details are provided in this Application.

The proposed REIP Framework also provides that the accrual of cost recovery for a Project under the REIP Surcharge shall terminate when and to the extent that the costs (or costs offset by net benefits in the case of AMI) are incorporated in rates in a utility's rate case. Section III.B.4.d of the REIP Framework. The Companies propose that the costs offset by net benefits for the AMI Project be incorporated in each Company's rate case following the installation period for the AMI meters.

The proposed REIP Surcharge provision filed in the REIP docket provides that the HECO Companies will file proposed changes to their respective REIP Surcharges based on renewable energy infrastructure projects that have been approved by the Commission net of the renewable energy infrastructure project costs transferred to and included in revised base rates. The filed proposed changes will include support calculations for the surcharge changes based on actual renewable energy infrastructure project expenditures, ratemaking cost recovery, tax depreciation, AFUDC, and rate of return, not to exceed the amounts approved by the Commission for recovery through the surcharge. To the extent that actual collections under the REIP Surcharge are different from the planned amounts, the HECO Companies will adjust the surcharge annually under the reconciliation provision of the surcharge.

2. Surcharge Cost Recovery for the AMI Project

The Companies propose to recover the incremental AMI Project revenue requirement impacts through a Commission-approved surcharge. The revenue requirements include the incremental costs of the AMI Project less the incremental quantifiable benefits created by the project. The incremental costs include: (1) new AMI meters installed at HECO beginning in May 2011, at MECO beginning in April 2014 and at HELCO beginning in April 2015; (2) retirement of existing non-AMI meters beginning with the receipt of the Commission Decision & Order in this docket; (3) purchase and installation costs for hardware related to the MDMS, deferred software development costs beginning in 2010 and related expenses; (4) purchase and installation costs for hardware related to the FNP/FRPs, as well as expenses related to the use of the Sensus owned, operated and maintained AMI Network; and (5) other AMI Project expenses, including damaged meter socket costs and outside consulting costs. The incremental quantifiable benefits created by the AMI Project include: (1) utility expense savings resulting from elimination of manual meter reads, as well as from field services savings related to remote disconnect/reconnect and remote read capabilities, (2) ratepayer revenue enhancements resulting from energy theft recovery, and (3) meter accuracy gains. The accounting and the ratemaking treatment for the AMI Project costs and incremental quantifiable benefits are described further below.

The Companies propose to recover the AMI Project incremental revenue requirements, net of quantifiable incremental benefits, on a prospective basis, subject to reconciliation. Traditional ratemaking methods will not be sufficient for financing the AMI Project, which, as discussed in Section VIII supra, will create substantial upfront costs to be offset by longer term benefits spread far into the future. This imbalance needs to be addressed by matching project-related cost incurrence with cost recovery in a manner that is fair both to ratepayers and shareholders.

The Companies further propose to recover the incremental revenue requirements of the AMI Project (i.e., net of quantifiable benefits) through an adjustment clause that better matches cost recovery with cost incurrence. In particular, the Companies propose that the adjustment clause be implemented by means of the proposed REIP Surcharge or in the alternative, through an AMI Surcharge. See Exhibit 22 for discussion on the revenue requirement calculation.

The Companies propose to recover the expected incremental revenue requirements of the AMI Project that are presented in this Application, subject to Commission approval. The Companies propose to recover the expected net revenue requirements using a per kWh surcharge, which is similar to the Companies' current recovery of expected program costs for demand-side management (DSM) programs. The Companies cost recovery through the surcharge is proposed to commence January 1, 2010 and adjust each year on January 1.

The estimated AMI Project surcharge levels are as follows[126] (in ¢/kWh):

Estimated Surcharge (¢/kWh)	2010	2011	2012	2013	2014	2015
HECO	0.0830	0.1482	0.1617	0.1023	0.0763	0.0645
HELCO	0.2128	0.2322	0.2181	0.1989	0.1819	0.3490
MECO	0.1534	0.1645	0.1562	0.1451	0.2586	0.0887

The Companies propose to adjust the surcharge based on revisions to forecast revenue requirements for the AMI Project that are filed with and approved by the Commission and based on an annual reconciliation of revenue requirements and revenues collected under the surcharge. In the annual reconciliation, incremental revenue requirements for the previous calendar year's actual capital investments, expenses, and benefits for the AMI Project will be compared to actual revenues collected. The difference will be included along with monthly interest charged or credited at the approved rate of return on rate base in the respective HECO Company's most recent interim or final decision in a rate case. The Companies propose to add this reconciliation adjustment to the current year's forecast AMI Project surcharge effective March 1 through December 31.

[126] Based on total AMI Project revenue requirement less imputed debt, rebalancing costs and internal labor. AMI Project revenue requirement impact to Maui Division only. See also Exhibit 21 Rate Impact of AMI for calculations.

The following illustrates the expected pattern of AMI Project surcharge and adjustment following Commission approval of the AMI Project;

- Initial surcharge - January 1, 2010
- Second Year surcharge – January 1, 2011
- Reconciliation of First Year surcharge – March 1, 2011 (includes both reconciliation plus Second Year surcharge that was effective January 1, 2011).

Revenue requirements for actual capital investments and expenses in the reconciliation calculation will not exceed the expected annual revenue requirements that are approved in this Application. Should the actual revenue requirements exceed those approved in this Application, the Companies will make a separate request to the Commission to recover those additional revenue requirements.

The reconciliation adjustment will also reduce the surcharge for the revenue requirements of AMI Project costs and net benefits that are reflected in approved rates after being included in the revenue requirements of a future rate case. The Companies will calculate such adjustments to AMI Project incremental revenue requirements based on interim decision and orders received in rate cases, and will further adjust incremental revenue requirements as needed upon final decision and orders in rate cases.

The surcharge for the AMI Project will terminate when all incremental revenue requirements are fully reflected in Companies' rates, and after any final reconciliation adjustment to the surcharge is completed.

3. <u>Need for Timely Cost Recovery</u>

As discussed above, the AMI Project will create substantial upfront costs that generally will not be offset by quantifiable benefits in the short term, but rather by longer term benefits to be realized far into the future. This imbalance needs to be addressed by matching project-related cost incurrence with cost recovery in a manner that is fair both to ratepayers and shareholders. Thus, the Companies propose to flow the incremental revenue requirement impacts of the AMI Project (i.e., net of quantifiable benefits) through an adjustment clause that matches cost recovery with cost incurrence. More specifically, the Companies seek authorization from the Commission to defer AMI Project costs and recover such costs through the proposed REIP Surcharge, pursuant to the REI Program proposed in the REIP docket, Docket No. 2007-0416, or in the alternative, through an AMI Surcharge.

The Companies provided a substantial discussion of the statutory support for the use timely cost recovery mechanisms in the RPS and REIP dockets. In addition, AMI is specifically identified in the REIP docket as a renewable energy project that should qualify for cost recovery through the REIP Surcharge.[127] Further support for using the REIP Surcharge and other timely cost recovery mechanisms can be found in (1) the terms of the HCEI Agreement; (2) surcharge mechanisms implemented in other states; (3) FERC Order No. 679; (4) NARUC's AMI Resolution; and (5) various other sources such as the Pacific Economics Group and federal legislation including EISA § 1307 and EESA. Exhibit 23 expands on each of the five supporting justifications.

As noted in the REIP Docket, the REIP Surcharge generally is not a means of raising capital prior to the approved projects' installation and use, but is intended to recover the revenue requirement of a REI Project until the revenue requirement is included in base rates. The REIP Surcharge is intended to facilitate raising capital by

[127] See generally the Companies' Reply Position Statement, filed September 17, 2008 in Docket No. 2007-0416.

providing investors assurance of a mechanism to recover the utilities' investment in renewable infrastructure in a timely fashion.

The cost recovery support provided by the REIP Surcharge will help the HECO Companies in their efforts to raise capital for renewable infrastructure projects, without degrading credit quality or increasing the cost of capital, which capital is in addition to funds needed for investments to maintain the reliability of the basic electric system. Under traditional ratemaking, the Companies have to wait for rate cases to be processed to begin recovering costs incurred to install new infrastructure, which means there can be a substantial lag in recovering costs, and even substantial cost under-recovery which can result in credit degradation and a higher cost of capital, which ultimately is paid by the ratepayers. To help avoid this, traditional ratemaking should be supplemented with other ratemaking tools, such as the proposed REIP Surcharge, which would allow cost recovery to begin as soon as new facilities go into service.

The Companies' Reply Position Statement in the REIP Docket pointed out that (1) there may be instances where capital assets already included in rate base are replaced by assets added as a result of an REI Project, and (2) the Companies may request accelerated recovery of the net costs of the displaced assets, which would have the effect of providing capital for the new project (although technically the HECO Companies would be recovering the costs of assets previously placed in service). The example was the existing meters that are displaced by "Smart Meters" as part of an AMI Project.

B. AMI PROJECT BOOK ACCOUNTING AND PROPOSED RATEMAKING TREATMENT

1. Incremental Costs

This section briefly describes the Companies' book accounting and proposed ratemaking treatment for the following incremental costs associated with the Companies' proposed AMI Project. Exhibit 24 describes the accounting and proposed ratemaking treatment in greater detail. A detailed description and discussion of the AMI Project components can be found in Section VII. Further discussion of the incremental benefits can be found in Section X.

a. New AMI Meters – For book accounting purposes, the Companies will capitalize the installed costs, include as utility assets, and depreciate over the current Commission approved depreciation rates for meters. For ratemaking purposes, the Companies propose to include new meters as utility assets in rate base and to recover this investment over a period of seven years from the time of installation. This represents an accelerated recovery of the Companies' investment in these new AMI meters.

b. Existing Non-AMI Meters – For book accounting purposes, the Companies will continue depreciating the existing non-AMI meters over the current Commission approved depreciation rates and continue including them as utility assets prior to the meters being replaced. For ratemaking purposes, the Companies propose accelerated cost recovery of their investment in existing non-AMI meters, beginning with the receipt of the Commission's decision and order in this docket. The AMI Surcharge would include the net of the revenue requirements of the accelerated recovery of the existing non-AMI meters and the revenue requirements of these meters in base rates, to the extent that the retirement of these meters is not reflected in base rates. HECO proposes to recover the remaining $13,960,000 estimated book value (as of December 31, 2009) of its existing non-AMI meters over a three-year period beginning upon receipt of the Commission's decision and order in this docket. MECO proposes to recover the remaining $4,899,000 estimated book value (as of December 31, 2009) of its existing non-AMI meters over a period beginning upon receipt of the Commission's decision and order in this docket and ending when MECO's meter installation begins in 2014. HELCO similarly proposes to recover the remaining $9,238,000 estimated book value (as of December 31, 2009) of its existing non-AMI meters over a period beginning upon receipt of the Commission's decision and order and ending when HELCO's meter installation begins in 2015. [128]

c. **MDMS Capital Costs, Software Development Costs, and Expenses**

i. **MDMS Capital Costs** – For book accounting purposes, the Companies will capitalize the installed costs of the MDMS hardware, include them as utility assets, and depreciate them over the current Commission approved depreciation

[128] Without approval of special ratemaking cost recover, the Companies would rely on traditional ratemaking methods to recover their investment in its existing meters and to recover the capital costs associated with the purchase and installation of the new advanced, solid state meters. The existing non-AMI meters would remain in rate base as a utility asset and be depreciated over the current Commission approved depreciation rates for meters. Upon replacement by a new advanced, solid state meter, the existing meter would be retired and removed from utility assets as it would no longer be considered "used and useful". The Companies would recover the remaining net book value of these retired meters via increased depreciation, based on depreciation rates calculated in its next depreciation study, on the remaining un-replaced meters left in service. Increased depreciation will allow for recovery of the investment in the existing non-AMI meters that were retired.

The cost of the purchase and installation of the new AMI meters would be capitalized and included as a utility asset in rate base upon being installed and placed in service. The meters would then be depreciated over the current Commission approved depreciation rates. The Companies would recover its investment in the new meters and earn a return on its investment through base rates as determined in a rate case proceeding.

Accelerated straight line cost recovery of the costs of new AMI meters (and timely cost recovery of such costs), and accelerated straight-line cost recovery of the costs of existing meters that will be replaced by the new AMI meters, will give investors greater assurance of recovery of their investment and demonstrate regulatory support for the initiative. This commitment to cost recovery will help to provide future sources of capital for the numerous future investments relating to HCEI.

rates. The Companies propose that ratemaking treatment follow book accounting treatment.

ii. **MDMS Software Development Costs** – Software development costs incurred during the preliminary stage (i.e., conceptual formation of software alternatives, determination of the existence of needed technology, and final selection of alternatives) and post-implementation/operation (i.e., training and application maintenance) stages of the AMI Project will be expensed as incurred for book and ratemaking purposes. During the application development stage (between the preliminary stage and the post-implementation stage), the Companies request approval to: (1) defer (i.e., capitalize) certain computer software development costs associated with the MDMS; (2) accumulate AFUDC on the deferred costs during the deferral period; (3) amortize the deferred costs over a 12-year period; and (4) include the unamortized costs in rate base. This is consistent with the ratemaking treatment for software development costs, as determined in other Commission proceedings, that requires prior Commission approval for specific software development projects. Absent approval to defer these costs the Companies would expense these costs as incurred. For ratemaking purposes, the Companies propose to include the unamortized deferred software development costs in rate base and to amortize over a period of 12-years.

iii. **MDMS Expenses** – For book accounting purposes, the Companies will record and recognize MDMS-related expenses as they are incurred. For ratemaking purposes, the Companies propose to include the MDMS-related expenses in revenue requirements in the AMI Project surcharge.

d. AMI Network Capital Costs, Lease Expense, and Other Expenses

i. **AMI Network Capital Costs** – For book accounting purposes, the Companies will capitalize the installed costs of the FNP/FRP, include them as utility assets, and depreciate the hardware over the current Commission approved depreciation rates. The Companies propose that ratemaking treatment follow book accounting treatment.

ii. **AMI Network Lease Expense** – For book accounting purposes, it has been determined that the monthly fee for the use of the AMI Network, discussed in Section VII, constitutes an operating lease. Based on generally accepted accounting principles, the Companies must recognize expense related to the lease on a straight-line basis over the term of the lease beginning with the effective date of the lease (i.e., upon Commission approval). As a result, expense recognition is greater than the lease payment in the early years of the term of the lease. The Companies propose that ratemaking be based on the lease payments as they are paid over the term of the lease. The HECO Companies respectfully request Commission assurance that the rate recovery of the AMI Network will be based on lease payments over the term of the agreement. Commission assurance that future ratemaking will be based on the lease payments will allow the Companies to record a regulatory asset in lieu of reflecting the straight-line lease expense for book accounting purposes. This regulatory asset would not be included in rate base as it does not represent investor provided funds.

iii. **Other AMI Network Expenses** – For book accounting purposes, the Companies will record and recognize AMI Network related expenses as they are incurred. For ratemaking purposes, the Companies propose to include the AMI Network related expenses in revenue requirements in the AMI Project surcharge.

e. <u>Other AMI Project Expenses</u> – For book accounting purposes, the Companies will record and recognize other AMI expenses as they are incurred. For ratemaking purposes, the Companies propose to include the outside consultant costs and damaged meter socket costs in the revenue requirements for inclusion in the AMI Project surcharge.

For any items where there is a mismatch in the timing of the expense recognition for book purposes and revenue recognition, a regulatory liability (or regulatory asset) will be created. All regulatory liabilities created would be deductions in the calculation of rate base for ratemaking purposes. This is described in detail for each above item in Exhibit 24.

2. <u>Offsetting Incremental AMI Benefits</u>

As indicated above, the Companies are not proposing to collect all of the AMI Project's costs through a surcharge. The Companies only propose to flow the project's incremental revenue requirements through the surcharge to the extent that the incremental revenue requirements are not captured in base rates or any other surcharge mechanism. Thus, the AMI Project costs recovered though the surcharge will be net of the incremental quantifiable benefits created by the AMI Project which are not captured in base rates or any other surcharge mechanism. The following briefly describes the Companies' book accounting and proposed ratemaking treatment for the following incremental benefits associated with the Companies' proposed AMI Project:

a. **Energy Theft Recovery –** For book accounting purposes, energy theft recovery will be embedded in the recorded revenues, which will be higher than they would have been without the energy theft recovery. For ratemaking purposes, higher revenues resulting from energy theft recovery will be reflected in the AMI Project surcharge to the extent they are not reflected in base rates.

b. **Meter Accuracy Gains –** For book accounting purposes, meter accuracy gains will be embedded in the recorded revenues, which will be higher than they would have been without the meter accuracy gains. For ratemaking purposes, higher revenues will be reflected in the AMI surcharge to the extent they are not reflected in base rates.

c. **Meter Reading Savings** – For book accounting purposes, meter reading savings will be embedded in the meter reading expenses, which will be lower than they would have been but for the AMI Project. For ratemaking purposes, the lower meter reading expenses will be reflected in the AMI Project surcharge to the extent that they are not reflected in base rates.

d. **Field Services Savings –** For book accounting purposes, field services savings will be embedded in the field services expenses which will be lower than they would have been but for the AMI Project. For ratemaking purposes, the lower field services expenses will be reflected in the AMI Project surcharge to the extent that they are not reflected in base rates.

XII

TOU TARIFF CHANGES

As provided for in the HCEI Agreement described in Section II, the Companies request approval for TOU rates as specified in Exhibit 25.

XIII

PROJECT REPORTING (TO THE COMMISSION)

In compliance with the Section 14 of the HCEI Agreement, beginning January 1, 2009, the Companies will submit an annual report to the Commission on the number of customers currently served, number who opted out (of TOU rates), customer load response, impact of TOU rates on customer's monthly bills and feedback received from customers. The HECO Companies, working with external experts, will also submit to the Commission an evaluation of the effectiveness of the Companies' TOU rates and will determine whether any changes are needed to the energy information communications and TOU rates to improve customers' energy responsiveness. The Companies will complete this evaluation by December 31, 2009 and will submit a second report one year after the full deployment of AMI. Progress on the AMI Project will be periodically reported to the Commission.

XIV

HECO'S, HELCO'S AND MECO'S CAPITALIZATION

A. HECO'S CAPITALIZATION

The authorized capital stock of HECO consists of 50 million shares of common stock, $6 2/3 par value (total authorized par value of $333.3 million), 5 million shares of cumulative preferred stock, $20 par value (total authorized par value of $100 million), and 5 million shares of cumulative preferred stock, $100 par value (total authorized par value of $500 million), or a total authorized par value of $933.3 million for common stock and cumulative preferred stock.

As of September 30, 2008, HECO had outstanding 12,805,843 shares of common stock of the par value of $6 2/3 per share, having a total par value of $85,387,140.

Common equity balances for HECO at year end for each year of the five-year period 2003-2007 were as follows:

2007	$1,110,462,167
2006	958,203,440
2005	1,039,259,140
2004	1,017,104,412
2003	944,442,770

Dividends paid on HECO's common stock for each year of the five-year period 2003-2007 were as follows:

2007	$27,084,000
2006	29,381,000
2005	50,895,000
2004	11,613,000
2003	57,719,000

The common dividend payout ratios (common dividends paid / net income for common stock) for each year of the five-year period 2003-2007 were as follows:

2007	52%
2006	39%
2005	70%
2004	14%
2003	73%

As of September 30, 2008, HECO had outstanding 1,114,657 shares of cumulative preferred stock of the par value of $20 per share, having a total par value of

$22,293,140. The preferred stock balance at year end for each year of the five-year period 2003-2007 was $22,293,140. Details of HECO's cumulative preferred stock are on file with the Commission under various docket numbers as set forth in Exhibit 26 and are incorporated herein by reference.

Dividends accrued on HECO's preferred stock for each year of the five-year period 2003-2007 were as follows:

2007	$1,079,907
2006	1,079,907
2005	1,079,907
2004	1,079,907
2003	1,079,907

See Exhibit 26 for the dividend rate for HECO's preferred stock, which remained the same for each year of the five-year period 2003-2007.

As of September 30, 2008, HECO had outstanding $551,580,000 in obligations to the State of Hawaii for the repayment of loans of the proceeds of special purpose revenue bonds and $31,546,400 of long-term borrowings from its financing subsidiary, HECO Capital Trust III. Details of each issuance are on file with the Commission under various docket numbers as set forth in Exhibit 26 and are incorporated herein by reference. As of September 30, 2008, HECO had outstanding $140,994,794 of external short-term borrowings, net of discount. HECO had short-term loans receivable of $60,150,000 from HELCO and $16,000,000 from MECO as of September 30, 2008.

During 2007, HECO made the following interest payments on the indicated obligations:

• Loans of proceeds of special revenue bonds	$27,166,613
• Long-term borrowings from HECO Capital Trust III	2,050,516
• Short-term borrowings from HEI	75
• Short-term borrowings from MECO	133,802
• Short-term borrowings from non-affiliates	2,939,128

B. HELCO'S CAPITALIZATION

The authorized capital stock of HELCO consists of 10 million shares of common stock, $10 par value (total authorized par value of $100 million) and 1 million shares of cumulative preferred stock, $100 par value (total authorized par value of $100 million), or a total authorized par value of $200 million for common stock and cumulative preferred stock.

As of September 30, 2008, HELCO had outstanding 2,177,315 shares of common stock of the par value of $10 per share, having a total par value of $21,773,150.

Common equity balances for HELCO at year end for each year of the five-year period 2003-2007 were as follows:

2007	$201,820,961
2006	175,099,595
2005	189,407,208
2004	186,504,537
2003	174,639,034

Dividends paid on HELCO's common stock for each year of the five-year period 2003-2007 were as follows:

2007	$0
2006	2,874,000
2005	9,720,500
2004	1,070,000
2003	7,934,000

The common dividend payout ratios (common dividends paid / net income for common stock) for each year of the five-year period 2003-2007 were as follows:

2007	0%
2006	41%
2005	77%
2004	9%
2003	71%

As of September 30, 2008, HELCO had outstanding 70,000 shares of cumulative preferred stock of the par value of $100 per share, having a total par value of $7,000,000. The preferred stock balance at year end for each year of the five-year period 2003-2007 was $7,000,000. Details of HELCO's cumulative preferred stock are on file with the Commission under various docket numbers as set forth in Exhibit 27 and are incorporated herein by reference.

Dividends accrued on HELCO's preferred stock for each year of the five-year period 2003-2007 were as follows:

2007	$533,750
2006	533,750
2005	533,750
2004	533,750
2003	533,750

See Exhibit 27 for the dividend rate for HELCO’s preferred stock, which remained the same for each year of the five-year period 2003-2007.

As of September 30, 2008, HELCO had outstanding $141,600,000 in obligations to the State of Hawaii for the repayment of loans of the proceeds of special purpose revenue bonds and $10,000,000 of long-term borrowings from HECO’s financing subsidiary, HECO Capital Trust III. Details of each issuance are on file with the Commission under various docket numbers as set forth in Exhibit 27 and are incorporated herein by reference. As of September 30, 2008, HELCO had short-term borrowings of $60,150,000 from HECO.

During 2007, HELCO made the following interest payments on the indicated obligations:

- Loans of proceeds of special purpose revenue bonds $7,041,375
- Long-term borrowings from HECO Capital Trust III 650,000
- Short-term borrowings from HECO 2,280,050

C. MECO'S CAPITALIZATION

The authorized capital stock of MECO consists of 10 million shares of common stock, $10 par value (total authorized par value of $100 million) and 1 million shares of cumulative preferred stock, $100 par value (total authorized par value of $100 million), or a total authorized par value of $200 million for common stock and cumulative preferred stock.

As of September 30, 2008, MECO had outstanding 1,582,602 shares of common stock of the par value of $10 per share, having a total par value of $15,826,020.

Common equity balances for MECO at year end for each year of the five-year period 2003-2007 were as follows:

2007	$208,520,627
2006	192,230,913
2005	194,190,117
2004	189,413,222
2003	187,194,550

Dividends paid on MECO's common stock for each year of the five-year period 2003-2007 were as follows:

2007	$9,900,000
2006	6,522,000
2005	13,728,500
2004	17,914,000
2003	12,390,000

The common dividend payout ratios (common dividends paid / net income for common stock) for each year of the five-year period 2003-2007 were as follows:

2007	84%
2006	35%
2005	74%
2004	92%
2003	68%

As of September 30, 2008, MECO had outstanding 50,000 shares of cumulative preferred stock of the par value of $100 per share, having a total par value of $5,000,000. The preferred stock balance at year end for each year of the five-year period 2003-2007 was $5,000,000. Details of MECO's cumulative preferred stock are on file with the Commission under various docket numbers as set forth in Exhibit 28 and are incorporated herein by reference.

Dividends accrued on MECO's preferred stock for each year of the five-year period 2003-2007 were as follows:

2007	$381,250
2006	381,250
2005	381,242
2004	381,252
2003	381,250

See Exhibit 28 for the dividend rate for MECO's preferred stock, which remained the same for each year of the five-year period 2003-2007.

As of September 30, 2008, MECO had outstanding $164,720,000 in obligations to the State of Hawaii for the repayment of loans of the proceeds of special purpose revenue bonds and $10,000,000 of long-term borrowings from HECO's financing subsidiary, HECO Capital Trust III. Details of each issuance are on file with the Commission under various docket numbers as set forth in Exhibit 28 and are incorporated herein by reference. As of September 30, 2008, MECO had short-term borrowings of $16,000,000 from HECO.

During 2007, MECO made the following interest payments on the indicated obligations:

• Loans of proceeds of special purpose revenue bonds	$7,918,980
• Long-term borrowings from HECO Capital Trust III	650,000
• Short-term borrowings from HECO	145,696

XV

FINANCIAL STATEMENTS

The Companies' audited financial statements for the year ended December 31, 2007 (audited by KPMG LLP), included as Exhibit 99.1 to HECO's and HEI's Form 8-K dated February 21, 2008, were filed with the Commission on March 4, 2008, and are incorporated in this Application by reference pursuant to HAR 6-61-76 of the Public Utilities Commission's Rules of Practice and Procedure, Title 6, Chapter 61.

The Companies' latest available balance sheets and income statements for the period ending September 30, 2008, were filed with the Commission on November 6, 2008, and are also incorporated herein by reference.

XVI

Wherefore, the HECO Companies respectfully request that the Commission approve:

(1) the commitment of capital funds in excess of $2,500,000 (estimated at $41,229,000 for HECO, $10,606,000 for MECO, and $13,190,000 for HELCO) for the AMI project;

(2) deferring certain computer software development costs (i.e., the "Stage 2" or "Application Development" costs, including the costs of designing, acquiring,

installing and testing the computer software) for the MDMS and accrue an AFUDC during the deferral period (total deferred costs are estimated at $9,134,000 for HECO, $2,021,000 for MECO, and $2,385,000 for HELCO);

(3) amortization of the MDMS deferred costs (including AFUDC) over a 12-year period (or such other amortization period as the Commission finds to be reasonable), and to include the unamortized deferred costs (including AFUDC) in rate base;

(4) cost recovery for ratemaking purposes of the remaining book value of its existing meters (that will be replaced with advanced meters) in the following manner for each of the Companies:

(a) HECO – beginning with the receipt of the Commission's Decision and Order on a straight-line basis over a period of three years for HECO,

(b) MECO – beginning with the receipt of the Commission's Decision and Order on a straight-line basis and ending when MECO's meter installation begins, and

(c) HELCO – beginning with the receipt of the Commission's Decision and Order on a straight-line basis and ending when HELCO's meter installation begins;

(5) cost recovery for ratemaking purposes of the capital costs associated with the purchase and installation of the new AMI meters over a seven-year period on a straight-line basis;

(6) the Companies to begin installing, on a first-come, first-served basis, advanced meters for all customers that request them and to implement TOU rates on an

interim basis for customers requesting the installation of advanced meters;

(7) the proposed Schedule TOU-R (Residential Time-of-Use) rates for HECO, HELCO, and MECO (all three divisions) and proposed Schedule TOU-G (Small Commercial Time-of-Use Service), Schedule TOU-J (Commercial Time-of- Use Service) and Schedule TOU-P (Large Power Time-of-Use Service) rates for HELCO and MECO (all three divisions)[129];

(8) recovery of all of the Companies' incremental cost associated with the AMI Project through the REIP Surcharge that is pending approval in Docket No. 2007-0416 or an AMI Surcharge mechanism approved by the Commission in this proceeding;

(9) the Sensus Agreement including its terms and conditions and a finding that the arrangement is prudent and in the public interest, and a determination that the Companies may include all costs, fees and related taxes to be paid by the Companies pursuant to the Agreement in its revenue requirements for ratemaking purposes and for the purposes of determining the reasonableness of the Companies' rates;

(10) recovery of AMI Network lease expense based on lease payments over the term of the Agreement; and

[129] All of the proposed TOU rates will be adjusted to align with the current Energy Cost Adjustment Clause at the respective Companies.

(11) such other and further relief as may be just and equitable in the premise.

DATED: Honolulu, Hawaii, December 1, 2008

HAWAIIAN ELECTRIC COMPANY, INC.
HAWAII ELECTRIC LIGHT COMPANY, INC.
MAUI ELECTRIC COMPANY, LIMITED

By ______________________________
Darcy L. Endo-Omoto
Vice President

STATE OF HAWAII)
) ss.
CITY AND COUNTY OF HONOLULU)

DARCY L. ENDO-OMOTO, being first duly sworn, deposes and says: That she is a Vice President of Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., and Maui Electric Company, Limited, Applicants in the above proceeding; that she makes this verification for and on behalf of HAWAIIAN ELECTRIC COMPANY, INC., HAWAII ELECTRIC LIGHT COMPANY, INC., and MAUI ELECTRIC COMPANY, LIMITED and is authorized so to do; that she has read the foregoing Application, and knows the contents thereof; and that the same are true of her own knowledge except as to matters stated on information or belief, and that as to those matters she believes them to be true.

Darcy L. Endo-Omoto

Subscribed and sworn to before
me this 1st day of December 2008.

Deborah Ichishita
Notary Public, First Circuit,
State of Hawaii

My Commission expires July 18, 2012

Doc. Date: 12/1/08 # Pages: 301
Name: DEBORAH ICHISHITA First Circuit
Doc. Description Application - Advanced Metering Infrastructure project
Deborah Ichishita 12/01/08
Signature Date
NOTARY CERTIFICATION

DEBORAH ICHISHITA
NOTARY
04-409
PUBLIC
STATE OF HAWAII

Sensus Agreement Summary

HECO executed an Advanced Metering Infrastructure Equipment and Services Agreement, dated October 1, 2008 ("Sensus Agreement"), with its AMI vendor, Sensus Metering Systems Inc. ("Sensus"),[1] whereby: (1) HECO will purchase from Sensus certain Sensus meters and third-party meters (to be installed by HECO or its contractors) in a quantity equal to at least 90% of the AMI meters required by the HECO Companies in connection with deployment of their AMI System;[2] (2) HECO will purchase, maintain and operate certain other Sensus FlexNet Network Portals ("FNP") and FlexNet Remote Portals ("FRP")[3]; and (3) in exchange for a monthly endpoint licensing fee, Sensus will license to HECO a Sensus owned, operated and maintained FlexNet AMI System (i.e., network) comprised of SmartPoints™, TGBs, RNI, WAN Backhaul, FCC licenses,[4] and other equipment and services provided to HECO in order to read HECO's electricity meters and provide two-way communications with respect to meters and demand response devices.[5]

Any equipment sold by Sensus to HECO under the Contract will be subject to a warranty period of the lesser of: (1) 12 months from installation at the customer's premises; or (2) 18 months from delivery to HECO.

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[1] MECO and HELCO are intended third-party beneficiaries of the Contract.

[2] Sensus meter prices during the mass deployment period are fixed. Sensus will conduct annual meter pricing reviews during the post-deployment period. Post-deployment meter price increases may not exceed $3 for residential and $10 for commercial meters, and should not exceed pricing available to other utilities.

[3] The contract provides for the installation of a total of 20 FNPs or FRPs (10 for HECO, 6 for HELCO and 4 for MECO). However, if additional FNPs or FRPs are required in order for Sensus to comply with the specifications related to the covered meters, then Sensus will provide such additional FNPs and/or FRPs to HECO at no charge.

[4] The Contract requires Sensus to maintain rights under and use its FCC license to transmit any and all data and two-way commands required to meet its obligations under the Contract, and Sensus may not allow any third-party use of the licensed spectrum without HECO's prior written consent.

[5] The Sensus Contract is confidential and proprietary and a copy will be provided after a protective order is issued in this Docket.

In addition, if the failure rate of Sensus' meters exceeds 2.5% in any 12-month period during the deployment period, HECO will be released of its requirement to buy 90% of its AMI meters from Sensus, in which case HECO may purchase whatever quantity of third-party meters it desires from alternative meter suppliers, and HECO would have discretion to purchase only communications board electronics from Sensus at a reduced price.

With respect to those items licensed (i.e., leased) to HECO, the Contract provides that TGBs sufficient to achieve the Contract's performance requirements will be provided by Sensus, who will be responsible for their ongoing repair and maintenance, and will provide any equipment and components necessary for their proper performance. The RNI will be located on HECO's property, but like the TGBs and related software, will be provided, owned, maintained and updated by Sensus.[6] Pursuant to the Contract, HECO will pay Sensus a monthly endpoint licensing fee for use of the Sensus FlexNet AMI System (i.e., the network). This monthly fee will be computed by multiplying the number of network-accessible meters by an initial base rate of 19¢/meter, which rate will be automatically adjusted over time in direct relation to certain U.S. Department of Labor Producer Price Index Industry Data.

HECO's Contract with Sensus is conditioned on HECO obtaining a satisfactory AMI project approval order from the Commission including: (1) approval of the Contract and its terms and conditions and a finding that the arrangement is prudent and in the public interest; and (2) a determination that HECO may include all costs, fees and related taxes to be paid by HECO pursuant to the Contract in its revenue requirements for ratemaking purposes and for the purposes of determining the reasonableness of HECO's rates. If such an order is not obtained within 12 months of the filing of this Application, then HECO or Sensus may, by written notice delivered within 30 days of such date, declare the Contract null and void.

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[6] The Contract does not include integration of the RNI into HECO's internal systems.

AMR versus AMI

"Advanced metering infrastructure," as defined by FERC is:

> . . . a metering system that records customer consumption (and possibly other parameters) hourly or more frequently and that provides for daily or more frequent transmittal of measurements over a communication network to a central collection point. AMI includes the communications hardware and software and associated system and data management software that creates a network between advanced meters and utility business systems and which allows collection and distribution of information to customers and other parties such as competitive retail providers, in addition to providing it to the utility itself.[1]

Thus, AMI is not limited to advanced meters, but refers to an entire infrastructure that ties advanced meters to a data management system and from there to other utility business systems.

There is no single, universally accepted definition of the components that, taken together, constitute an advanced metering infrastructure.[2] When analysts, utilities, regulators, stakeholders and others use the term "advanced metering infrastructure" in the case of electric utilities, they do tend to refer broadly to a collection of hardware (e.g., meters and computer processors), software (e.g., billing system computer programs) and other elements that taken together permit the utility to perform certain functions.[3]

Components commonly associated with AMI include:

(1) Interval meters, that can record and store usage data on hourly or more frequent basis;

(2) Two-way communications network between meter and supplier/utility that can send usage data from the meter to the utility; and send pricing, load control and other signals from the utility to the customer's premises;

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[1] FERC Staff Report, Assessment of Demand Response & Advanced Metering, Docket No. AD-06-2-000, August 2006, Appendix A, Glossary ("FERC Staff Report"); FERC-727 and FERC-728, OMB Control Nos. 1902-0214 & 1902-0213, FERC Survey on Demand Response, Time-Based Rate Programs/Tariffs and Advanced Metering Infrastructure, Glossary.

[2] See Nancy Brockway, Advanced Metering Infrastructure: What Regulators Need to Know About Its Value to Residential Customers, Nat'l Regulatory Research Inst., February 13, 2008 ("NRRI Paper") at 6.

[3] See NRRI Paper at 6.

(3) A meter data management system ("MDMS"), that can handle large amounts of information concerning individual customer usage profiles; and

(4) Utility operational software, that can make use of the granular usage data produced through the meters, communications network, and meter data management system.[4]

AMI is sometimes confused with automated meter reading, or "AMR," which in turn typically means remote meter reading, as by a hand-held device or a device on a utility truck driven by the meter location (i.e., "Drive-By AMR"), picking up a signal from the meter to record the usage. However, AMI goes beyond AMR in that interval data is being captured and transmitted multiple times daily (versus monthly) by a fixed, radio-frequency ("RF") network. The capture of interval data and integration with the Companies' Customer Information System ("CIS") will provide many quantifiable and intangible benefits, serve to enable other future applications such as the DR and Dynamic Pricing, and support the future Smart Grid.

It is useful to note what AMR is not. AMI includes advanced metering (in particular, so-called interval meters, capable of recording and storing usage data at hourly intervals, if not shorter intervals). AMR does not have to involve interval metering – the customer still could be paying a traditional, constant rate with the metering measuring only total usage in a month without regard to usage at particular times of day. Therefore, a utility can install interval meters without installing an entire advanced metering infrastructure.[5]

Nor does AMR imply a two-way communications system and a MDMS. AMI, by contrast, can enable remote meter reading; in fact, the meter can be read from a central data

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[4] See NRRI Paper at 6-7.

[5] See NRRI Paper at 9. Some interval meters support static time-of-use ("TOU") pricing by means of a device added to the ordinary non-interval meter that allows the utility to collect usage information hourly. The utility then downloads the data monthly. AMI meters, by contrast, are also capable of sending and receiving meter and other data when called upon to do so, rather than merely storing it for monthly retrieval. See id.

storage and management location, by reading the signals communicated over the AMI network.[6] While many of these same meter readings can be achieved by AMR, AMI allows additional benefits due to the ability to query the meter frequently, or as needed. For example, utilities need to report their sales on a monthly basis. Without actual meter readings, this is an estimate, and utilities have found this to be a labor intensive report to produce. With advanced metering, utilities can prepare this report using actual meter readings as of midnight, for example, on the last day of the month.[7]

AMI is also much more capable of detecting energy theft than simple AMR systems. The "infrastructure" in an AMI system includes information systems that are capable of processing large amounts of interval data for use in discovery of energy theft. AMI can intelligently sort and prioritize meter tampering flags. This contrasts dramatically with AMR systems that generally only automate the monthly consumption read.[8]

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[6] See NRRI Paper at 9.

[7] FERC Staff Report at 35.

[8] See Re Application of San Diego Gas & Electric Company (U-902-E), Cal. Pub. Util. Comm'n Application 05-03-015, Rebuttal Testimony of James Teeter, San Diego Gas & Electric Testimony, (September 7, 2006) at JT-3.

Technology Selection

Mesh RF and Powerline Carrier Communications Technology Vendors

The Companies eliminated mesh Radio Frequency ("RF") and Powerline Carrier ("PLC") technologies as potential, front-end network topologies, in favor of non-mesh RF networks. Mesh technologies were not considered favorable due to the higher number of network devices required, the use of unlicensed RF frequencies, and lower RF transmission power when compared to the Sensus licensed, fixed RF network technology. Standard PLC technologies were not considered to have adequate bandwidth for AMI applications. High speed PLC (Broadband Over Powerlines or BPL) has both technical and cost issues and HECO had less than favorable experiences in piloting BPL on Oahu. Figure 1 provides details regarding PLC and BPL technologies.

Figure 1

Summary of Power Line Based AMI Vendors						
	Local Area Network (LAN)					
AMI Vendor	Injection Point	Addressability (/phase/feeder/bus)	Data Rate (down / up bps)	Distance (linear miles)	Comm Protocol	Additional Equipment
Cannon	Substation ≤ 24 kV	6,000	74	20-30 miles w/o repeater	poll-response	Repeaters Capacitor blocking
Current	CT Backhaul points along distribution feeders	10-15 service transformers per CT Backhaul point	EVDO: 300-500 down; 300-400 up GPRS/1x-RTT: 60-90 kbps	~1 per CT Backhaul point	2-way	CT couplers & bridges over transformers
Echelon	Distribution transformer	6-10 per xfmer	3.6 - 5.4 kbps (raw)	0.25	2-way	none
Hunt TS2	Substation ≤ 24kV	27,000	510 / 0.0008	150-200	2-way	none
TWACS by DCSI	Substation: ≤ 35 kV	33,000	30 / 15	150	poll-response	none

RF Communications Technology Vendors

Within the past several years, meter manufacturers have worked closely with many AMI communications technology vendors such that meter vendors can offer the utility a choice of communications technology. The potential RF network vendors for the Companies' AMI Project are described below and Figure 2 provides additional detail.

- Elster Group: Elster is a leading AMR/AMI company. According to Elster literature, its EnergyAxis AMI product provides intelligent, two-way communications to all meters using a spread spectrum, frequency hopping, and controlled mesh radio frequency network in the unlicensed 900 MHz band. Unlike systems that require separate equipment for network communications, EnergyAxis offers the choice of meter-based or non-meter network collectors, so deploying an EnergyAxis network can be as simple as installing the meters in the sockets. EnergyAxis is designed for both residential and commercial & industrial applications. As the utility's service area grows, EnergyAxis local area networks automatically adjust to include the new meters. Utility size is not a factor. EnergyAxis is scalable to multi-million meter deployments while at the same time being cost effective for smaller utilities or strategic deployments. Installation and maintenance costs are minimized because EnergyAxis meters handle the registration and network communication process automatically. When the communication link is disrupted (for example, new construction blocks the signal path), the meter will automatically seek another route back to the system. The EnergyAxis system became available in 2003 and is in widespread use throughout the world. The Companies have not pursued this vendor's EnergyAxis product because it uses unlicensed, mesh network. However, HECO is using Elster A3 C&I meters with embedded Sensus FlexNet communications technology.

- Eka Systems: According to Company literature, Eka Systems is working with equipment from major manufacturers such as, Elster, GE, Itron, Landis+Gyr, and others. Their EkaNet Wireless Electric Nodes build self-organizing wireless mesh networks for electric metering applications, are plug-and-play and support a broad range of residential, commercial, and industrial meters - both domestically and internationally. EkaNet "under-the-glass" solutions are perfect for electric utility companies' commercial and industrial as well as residential AMI/AMR, and sub-metering applications. EkaNet Electrical Nodes offer remote setup and configuration capabilities and provide access to all meter functions and communications capabilities. They enable reliable 2-way communications and highly secure wireless mesh networking with all EkaNet Nodes. The architecture is noted as self-managing and self-healing in order to handle complex data demands and large scales. Eka Systems has a small presence in the United States and may impose a continued operations and support risk for the Companies. In addition, the Companies have elected not to consider Eka systems due to their use of mesh networks.
- Hexagram Star: Hexagram Star's technology has proven itself in the context of gas metering. However, its ability to support electric metering has yet to be seen. Although Pacific Gas & Electric recently initiated a limited test on Hexagram Star's technology, the Companies have chosen not to implement a Hexagram Star system due to the higher technology risks.
- Itron Fixed Network 2.0: Similar to Cellnet, Itron is one of the most established AMR/AMI companies and has been selected by several large utilities including San Diego Gas & Electric and Southern California Edison. As with Elster, the Itron OpenWay product provides meter-based as well as standalone takeout points for its AMI network. The

Companies have not pursued this vendor because it uses unlicensed, mesh network technology.

- Landis + Gyr (Cellnet): Cellnet, an established AMR/AMI company, was acquired by the Bayard Group, which consolidated several meter brands under the Landis + Gyr banner. According to Company literature, L&G uses a Mesh Solution that provides intelligent automation for utility advanced metering and consumer energy management programs. The FOCUS AX Universal RF endpoint offers an integrated design with the FOCUS AX meter for use in residential deployments. The endpoint transmits and receives data through a robust and self-healing mesh network utilizing the 902 to 928 MHz FHSS unlicensed frequency. With added ease of use and scaling intelligence, their residential AMI meter can prioritize messages based on application, expand to millions of endpoints, and provide control through a user-friendly browser-based interface for network and data management. The residential AMI meter measures kWh, kW, and includes TOU functionality. The meter features Digital Multiplication Measurement Technique, meets ANSI standards for performance and utilizes ANSI C12.19 protocol. The Companies have not pursued this vendor because it uses unlicensed, mesh network technology.
- Sensus Metering Systems: Sensus utilizes a fixed RF network (non-mesh) communications technology which operates in a licensed RF spectrum. Advanced models are becoming available in both residential (iConA) and commercial/industrial (APX) versions that offer flexible, over-the-air programming, low cost, and high capability. The Companies have several years of experience with Sensus AMI meters and have worked with Sensus and other utilities to acquire advanced meter functionality. The use of a licensed, fixed RF network with relatively high transmission power limits the number of network "sites" and

simplifies future network operations and maintenance for the Companies. The Southern Company is deploying approximately 4 million meters across their service territory and Alliant Energy and Portland General Electric are contemplating large AMI meter deployments pending successful completion of their Systems Acceptance Test phase.

- Silverspring Networks: Silverspring is an IP-based AMI communications company. They do not manufacture meters but their network interface card (NIC) technology is available for electricity meters from L+G, GE, Itron and Sensus, providing flexibility to the utility. They also provide a wide range of in-home communication options such as 802.15.4, ZigBee and 6LoWPAN. According to Silverspring literature, their technology provides secure, two-way communications, remote upgradeability and advanced metering capabilities. Florida Power and Light has implemented a 100,000 meter pilot using Silverspring Networks and Pacific Gas & Electric has selected them as their AMI communications technology provider. Silverspring Networks uses a form of RF mesh technology; therefore, the Companies have not pursued this vendor's product although their technology has been integrated into Sensus latest products. It has been reported that a major meter manufacturer is collaborating with Silverspring Networks on the PG&E AMI project and Silverspring are almost ready to announce several additional, major contract awards.

Figure 2

RF AMI/AMR Vendors											
RF AMI Vendor	Home Area Network (HAN)	Local Area Network (LAN)					Wide Area Network (WAN)				
	Type	Spectrum	Topology	Data Rate (kbps)	Tx Power (W)	Distance (km)	Spectrum	Topology	Data Rate (kbps)	Tx Power (W)	Distance (km)
Cellnet (E,W,G)	N/A	Unlicensed: 902-928 MHz	heirarchical 1-way	19.2	0.1	0.4-1.2	Unlicensed: 902-928 MHz	mesh	19.2	1	8
Cellnet InfiNet (E)	LAN	Unlicensed: 902-928 MHz	mesh 2-way	19.2	0.05	0.4-0.8	Unlicensed: 902-928 MHz	mesh	19.2	1	8
Elster Energy Axis	LAN	Unlicensed: 902-928 MHz	mesh 2-way	19.2	0.25	0.16-0.56	Phone/ cellular		N/A		
Eka Systems	LAN (Bluetooth)	Unlicensed: 902-928 Unlicensed: 2.4GHz ISM Bluethooth	mesh 2-way	76.8 (@ 915Mhz) 1024 (@ 2.4GHz)	0.1	0.45	Cellular/ TCP/IP		N/A		
Hexagram Star	N/A	Licensed: 450-470 MHz 1-way (2-way in dev.)	heirarchical	1.2	1	1.6-3.2	Cellular/ TCP/IP		N/A		
Information Intellect	LAN	Unlicensed: 902-928 MHz	mesh 2-way	19.2	1	1.6	Cellular/ TCP/IP		N/A		
Itron FN 2.0	N/A	Unlicensed: 902-928 MHz	heirarchical 1-way	16.384	0.1-1	0.24-1.20	Cellular/ TCP/IP		N/A		
Itron OpenWay	Zigbee	Unlicensed: 902-928 MHz	mesh 2-way		1	0.27-0.76 1.6 (LOS)	Cellular/ TCP/IP		N/A		
StatSignal	LAN	Unlicensed: 902-928 MHz	mesh 2-way	2.4	0.1-1	0.56-0.88	Cellular/ TCP/IP		N/A		
Sensus FlexNet (AMDS)	LAN	Licensed: 8kHz band w/i 889-960 MHz	heirarchical 2-way	8	1-2	5.6 -29	No WAN		N/A		
Silver Springs Networks	LAN	Unlicensed: 902-928 MHz	mesh 2-way	96	1	5.6	Cellular/ TCP/IP		N/A		
Tantalus	LAN	Unlicensed: 902-928 MHz	mesh 2-way	9.6	0.4	0.4	Licensed: 5 kHz band w/i 220 MHz	heirarchical	1.6-3.2	5	32-48
Trilliant	Zigbee (LAN)	Unlicensed: 2.4 GHz	mesh 2-way	256	0.01-1	0.96-2.80	Cellular/ TCP/IP		N/A		

Final AMI Vendor Selection

Sensus Metering Systems ("Sensus") fixed RF network technology and metering was selected by the Companies. The Sensus AMI technology provides a relatively sparse network infrastructure (i.e., minimum number of TGBs[1]), the use of a licensed RF spectrum, and tight integration of the metering technology, network infrastructure and software. As further discussed below, Sensus' AMI technology was evaluated through various field tests and pilot programs at HECO, each designed to examine specific aspects of the technology.

[1] TGB denotes Sensus' Tower Gateway Basestation.

Based on the results of these pilot programs and favorable experiences with Sensus' technical and operational support during these programs, HECO determined that Sensus' AMI technology would provide the best solution for its service area and ratepayers. Sensus' AMI technology systems offer the following features:

- Single tier LAN+WAN architecture simplifying network operation and maintenance;
- Two-way RF performance (power, range, modulation, boost and buddy mode);
- Bifurcated data collection and hosted network monitoring facilitating system maintenance and trouble shooting;
- Minimization of future system support risk as a result of Sensus being an established, national communications company;
- Utilization of Sensus' country-wide (including Hawaii) licensed RF spectrum; and
- The ability for the Companies to leverage system enhancements and product development driven by large U.S. utilities (e.g., Southern Company, Portland General Electric and Alliant Energy) that have selected Sensus as their AMI vendor.

Pilot Testing of Sensus FlexNet Technology

In 2006, HECO initiated a series of pilot projects to examine the capabilities of Sensus' FlexNet AMI technology, network coverage, meter deployment processes, data capture for billing determinants and load profile/interval data capture. As described in Section VII of the Application, HECO has conducted three AMI pilot projects.

HECO entered into a contract for its first AMI pilot on August 1, 2006. This pilot involved an initial investigation into the functionality of Sensus' FlexNet technology. The first two TGBs were installed atop the Prince Kuhio Hotel in Waikiki and the Five Regents condominium in Salt Lake, and 500 FlexNet meters were randomly distributed throughout metropolitan Honolulu.

HECO entered into contract for its second AMI pilot on January 9, 2007 to investigate the ability of Sensus' FlexNet technology to collect data reliably for billing purposes. In this pilot, a third TGB was added at Mauna Kapu in the Makakilo area and over 3,000 FlexNet meters were installed in the Ocean Pointe area in Ewa Beach. The meters for this phase replaced all existing meters within a contiguous area, comprising three HECO meter reading routes. This allowed the evaluation of the FlexNet system in a fully populated AMI network environment. This phase also tested a meter installation contractor's (Honeywell Utility Services) ability to perform the deployment.

On July 1, 2007, HECO entered into contract for its third AMI pilot. This pilot involved the addition of two more TGBs, at Koko Head and Pu'u Papa'a, and approximately 400 residential meters. The objective of this phase was to extend the FlexNet coverage area so that it could test the ability to support interval data collection for the Dynamic Pricing Pilot ("DPP") and HECO's 2008-2009 Class Load Study ("CLS") programs. The AMI meters for these two programs were distributed throughout the entire Island of Oahu, which allowed HECO to more extensively test and evaluate the range and penetration capability of the AMI system.[2]

Additional meters have been installed under HECO's pilot AMI programs for various reasons. For example, meters were added so that they could repeat (act as buddies) messages between a TGB and an endpoint (meter). This is used to economically extend the range and penetration of the system. Meters were also added to provide remote meter reads (over the air) for meters that are difficult to access. Evaluation of the actual performance shows that most of

[2] A high level view of the pilot FlexNet system that resulted from the Companies' ongoing pilot activities is attached hereto as Exhibit 5.

the meters can reliably communicate with multiple TGBs. Approximately 7,700 AMI meters have been deployed to date.[3]

The installation and continued operation of HECO's AMI pilots has expanded the Companies' knowledge and experience with respect to Sensus' AMI technology. As a result of its AMI pilot projects, HECO has gained experience with the following:

- Validation and billing of all Ocean Pointe residential meters (over 3,000 customers) using over-the-air reads on the FlexNet network;
- Validation and billing of all Ocean Pointe C&I meters (52 customers) using over-the-air reads;
- Gathering of customer load information, over-the-air, for the DPP evaluation (nearly 400 customers) at 15-minute intervals;
- Gathering of CLS interval data information, over-the-air (nearly 500 customers), at 15-minute intervals; and
- Over-the-air demand resets.

The operation and performance of the pilots has been closely monitored and system improvements have been implemented to maximize the AMI network performance. As meter distribution density increases, the network is designed to automatically optimize itself to utilize new meters as buddies for meters with a poor communication history. As of February 2008, less than 2% of HECO's installed AMI meters exhibited poor communications rates (i.e., zero messages heard from a meter over a 24 hour period). A table showing the overall performance statistics of the HECO pilot system and a graph illustrating the improvement of the pilot system's performance over time is provided on page 11.

The performance of the Companies' AMI network will continue to improve as the AMI Project moves forward. Proper TGB distribution will enhance the network's ability to reach

[3] These figures are current as of November 10, 2008. An illustration of the geographic deployment of these meters on Oahu is attached hereto as Exhibit 6.

more meters. The current AMI pilot system contains 5 TGB sites on Oahu. However, Sensus' RF propagation study indicates a need for 9 sites with 15 TGBs on Oahu, 3 sites with 3 TGBs on Maui and 7 sites with 7 TGBs on the Big Island. As more TGBs are added, the percentage of meters exhibiting poor communications rates should decrease as a result of greater overlap in coverage[4].

In addition, new technologies and techniques available now or in development should further improve FlexNet performance. For example, FlexNet Network Portals ("FNP") will be used at strategic locations to forward messages between the meters and the TGBs. HECO has one FNP at its Ward Avenue facility and a second FNP at a site above the Kahe Power Plant and the operational performance of these sites is encouraging.[5] Sensus has also developed a FlexNet Remote Portal ("FRP"), which allows messages to be relayed directly through an Internet connection including cellular technology. HECO recently received training on the FRP product and plans to field test FRPs in 2009.

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[4] The Sensus Equipment and Services Agreement provides a guarantee of minimum performance levels.

[5] Moreover, the new Sensus FlexNet meter product specifications contain numerous communication improvements. Under the new specifications, message packages will be changed from FSK7 to FSK13 (FSK denotes Frequency-Shift Keying, a modulation technique in which two different frequencies in the carrier signal are used to represent the binary states of 0 and 1), which will allow more historical reads to be packaged into each message transmission. The load profile (LP) downloads will also be considerably improved since meters can be programmed to automatically transmit their LP information without over-the-air requests (as the current meters require). This should improve LP download performance to match the performance level of the over-the-air reads.

Pilot System Performance and Performance History

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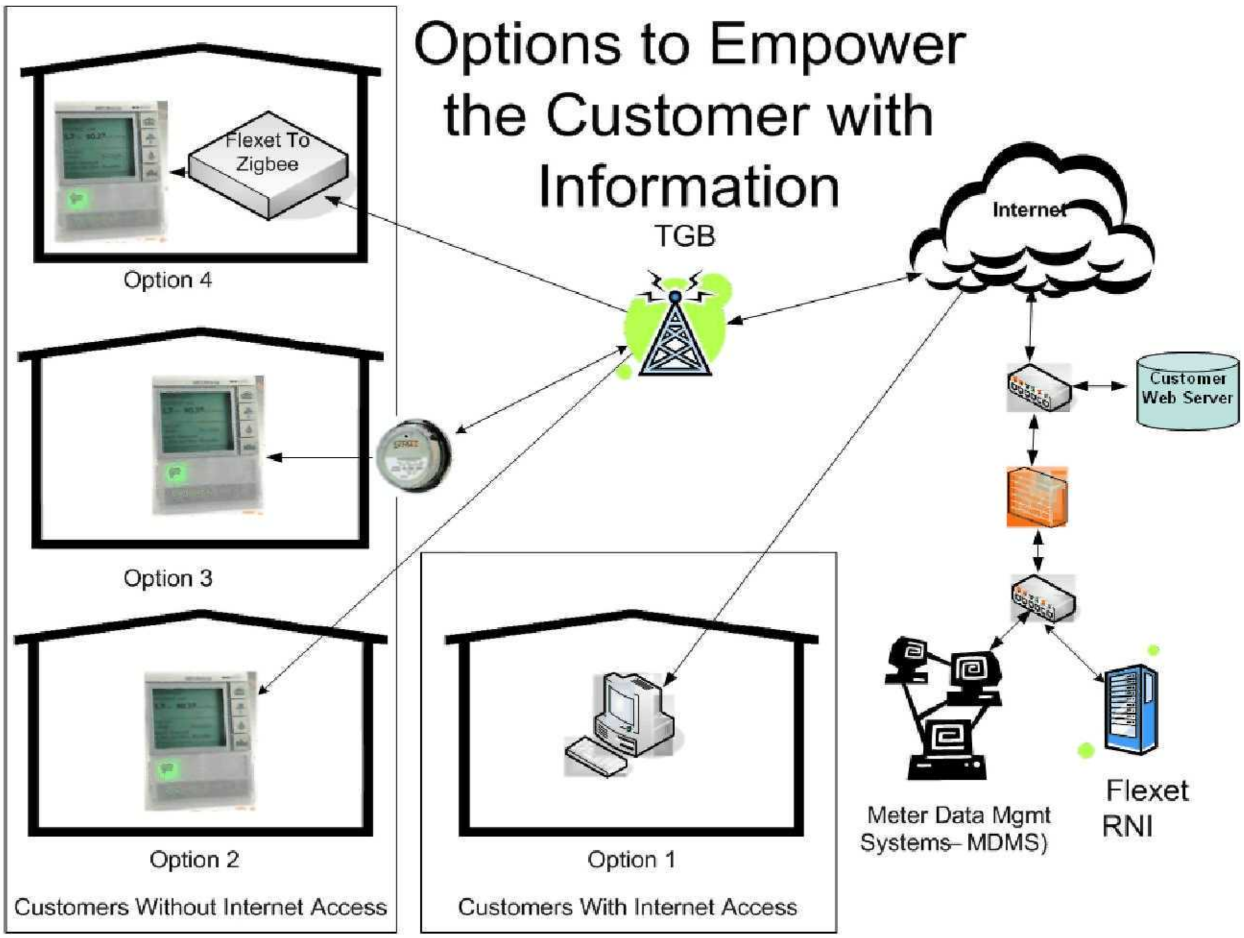
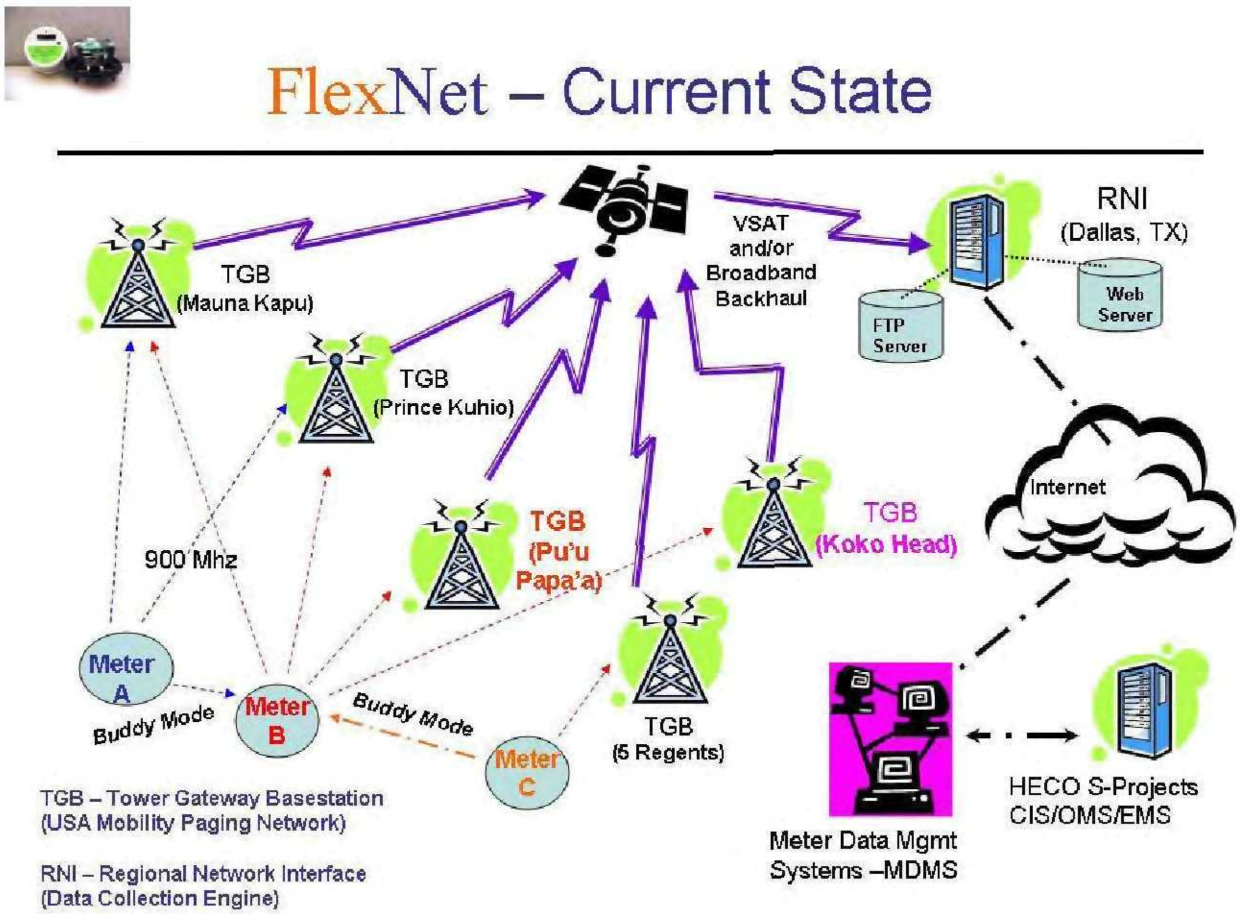
Options to Empower the Customer with Information



High Level View of the Pilot FlexNet System



AMI Pilot System on Oahu
Meters and Tower Gateway Basestations

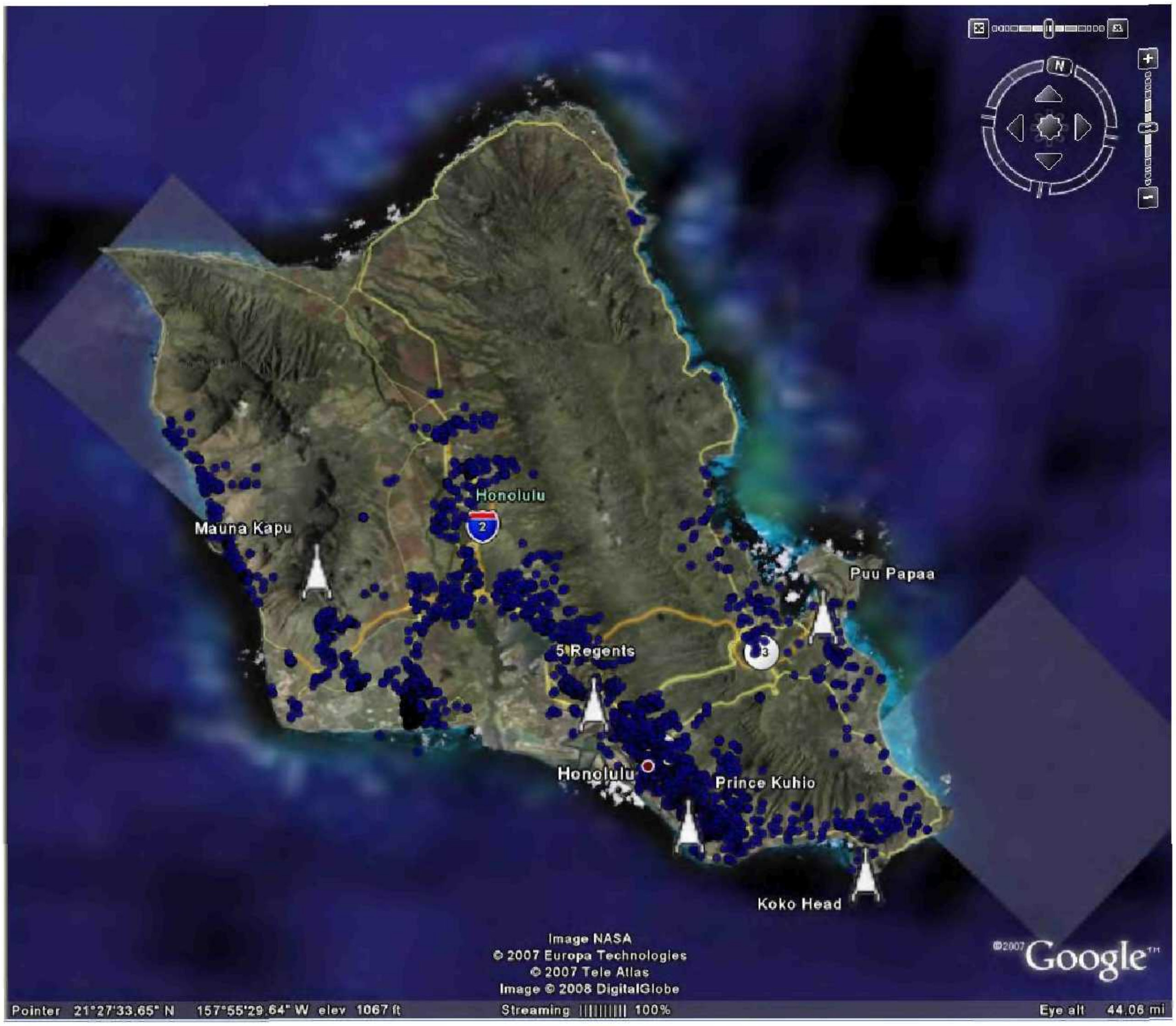


Exhibit 7 contains confidential information and will be provided

after a Protective Order is issued in this proceeding.

MDMS

MDMS Functions

Meter data management system ("MDMS") functions include: (1) collection system integration; (2) validation, estimation and editing; (3) versioned data storage; (4) calculation and aggregation; and (5) data exports and interfaces.

1. Collection System Integration

The HECO Companies currently employ three meter reading methods: (1) Manual readings using handheld units and Itron MVRS software; (2) Remote data capture using telephone or cellular phone connections and Itron MV90 software; and (3) Remote data capture using Hunt Technologies' Turtle Powerline Carrier ("PLC") system. The MDMS will support these three existing meter reading processes as well as the new AMI systems. In general, the MDMS will be designed to do the following:

- Manage the collection of meter readings from multiple technologies;
- Simplify the integration of future meter reading technologies; and
- Enable ad hoc, off-cycle read requests by the customer information system.

2. Validation, Estimation and Editing

Missing, redundant and incorrect data is inevitable. Data validation, estimation and editing ("VEE") identifies problematic data routed from meter data collection systems before it reaches other utility systems and provides tools for reconciling that data according to best practice rules and meter-specific parameters.

Having the flexibility to handle data anomalies such as gaps, overlaps and redundancies, as well as tolerance issues between consumption reads and interval data, with a reliable, auditable process is a critical MDMS feature. The MDMS will provide the Companies with the ability to specify validation logic via an integrated calculation engine – another key feature of an effective MDMS. When validation fails, the MDMS can be configured to execute contingencies, such as automatically estimating the read or passing a "no-read" to produce a failed validation report.

Effective VEE will provide the Companies with the ability to create standard parameter-based and user-defined algorithms, with full transparency and reporting on the development of those algorithms. The fundamental validation and estimation functions envisioned by the Companies include:

- Estimation of interval data based on meter readings;
- Replacement of all values with a constant;
- Multiplying or dividing values by a constant;
- Adding or subtracting a constant;
- Sliding a range of interval data ahead or back in time;
- Performing linear interpolation;
- Splitting or combining intervals; and
- Restoring previous versions.

In addition, the utilities should be able to edit values using a host of standard editing functions such as:

- Adding or replacing values manually;
- Modifying read status;
- Displaying or editing multiple reads;
- Copying or cutting and pasting a string of values from one meter to another; and
- Copying or cutting and pasting values from a spreadsheet.

3. Versioned Data Storage

Versioning maintains snapshots of each meter read associated with a time reference, making it much easier to resolve billing issues, process off-cycle events such as customer move-in/move-out, and maintain data accuracy across infrastructure changes such as meter exchanges. Versioned data is also critical to maintaining data integrity as that data is shared across multiple utility systems (i.e., demand response ("DR"), load research, forecasting, distribution asset analysis, etc.). As this single source of data becomes a central resource to multiple utility systems, the ability to reproduce a data set as it would have appeared at a particular date and time becomes vital.

The MDMS versioning process will provide log records indicating which user or VEE process made changes to the data. For example, if a reading changes five times, the MDMS will create five versions of that reading, each of which also will have a reference time period, indicating when it was the current version.

4. Calculation and Aggregation

Utilities have traditionally relied on external spreadsheets for the complex calculations required for their large commercial and industrial energy billing. Billing determinants used for time-of-use and critical peak pricing programs, for example, might require complex load calculations, aggregations and unit conversions. In the past, the pool of customers that have traditionally required these complex calculations has always been small relative to the total number of utility customers who require flat-rate usage billing. Dynamic pricing programs, net metering and other customer-focused programs will require that the MDMS incorporate features to automate these functions.

The MDMS will be provided with an integrated calculation engine to enable the Companies to dispense with hard-to-maintain spreadsheets and manual, error-prone methods for producing billing determinants. A calculation engine will support all of the common mathematical operators and functions as well as conditional and logical functions, ideally in a simple, intuitive spreadsheet interface. Examples include:

- Common operators: +, –, x, /, square root, square, sine, cosine, etc.;
- Condition/logical functions: if, and, or, not, >, =, etc.;
- Time and date functions: max, min, avg, total, etc.; and
- Unit conversions: kWh/kVARh to kVAh, power factor/V^2h to V, etc.

This broad functionality enables users to calculate nearly any complex load, loss or aggregation for billing applications, as well as calculations for other utility processes, such as estimation in VEE. Within the context of an MDMS, billing determinants can be calculated and delivered automatically upon the request of the billing system with no manual intervention. A calculation engine simplifies updating and maintaining calculations while versioning tracks changes. Standard MDMS interfaces make new and edited calculations immediately available for all utility applications. This puts an end to two problems. First, it replaces manual data import and export processes with automated processes that are secure and auditable. Second, it provides a single calculation for use by two or more utility systems. No longer does the same load data generate slightly different values depending on which utility spreadsheet was used.

5. Data Exports and Interfaces

A fundamental goal of the AMI project is to share meter data. Turning meter data into valuable knowledge that can be used by other utility systems depends on the MDMS' ability to deliver that data to employees and systems throughout the Companies with minimal IT support and manual intervention.

Effective MDMS solutions address the multi-vendor nature of a utility's meters, meter data collection technologies and business systems with an "open architecture" approach. Open architecture means the MDMS can export data to a wide variety of file formats (such as Microsoft Excel and Access) and provides a library of standard interfaces that utility business systems and third party applications can use to request and receive data from the MDMS. The use of industry programming standards, such as XML, helps minimize reprogramming to accommodate new applications and system integrations.

Accordingly, it makes no difference whether monthly usage data is collected by a handheld computer from a residential electricity meter, or if it is interval commercial and industrial data from a fixed network. All meter data becomes valuable information not only for utility billing but for:

- Analytical reporting such as time-of-use quantities by meter, peak days, coincident and non-coincident peaks, zero usage at active premises, usage at inactive/disconnected premises, interval data gaps, etc.;
- Outage event management;
- Life cycle management for assets and materials;
- Customer service interfaces to support billing inquiries;
- DR program management;
- Web-based customer care applications;
- Revenue protection programs; and
- Distribution system asset optimization programs.

MDMS Product Selection

In 2008, the Companies initiated MDMS pilot projects that allowed internal users to utilize the core MDMS software and also allow meter data to be imported into the MDMS and billing determinant exchanges with a CIS test environment. The pilot projects are routing data from the AMI meters deployed under HECO's prior AMI pilots, through a Sensus RNI, and into the MDMS, which generate the billing determinants and pass this data on to the CIS test environment.

The Companies retained an AMI consultant, Enspiria Solutions, Inc. to assist with the selection of vendors for the evaluation of MDMS products.

The Companies plan to implement the MDMS in advance of full AMI deployment to ensure that the MDMS application is operating reliably before the Companies enter the full meter deployment phase, where meters are being rapidly installed on a daily basis.

AMI Systems Integration and OMS Support[1]

In the AMI System, the MDMS will serve as the central integration component. On the front-end, the MDMS interfaces with legacy meter reading systems (MVRS, MV-90, and Turtle) and the Regional Network Interface ("RNI"). On the back-end, the ultimate goal[1] is for the MDMS to interface with the Companies' CIS, OMS, GIS and other systems. In the future, data from the utility Load Management System ("LMS"), and requests from the OMS could be implemented. However, in the near term, integration will be limited to the CIS.

The MDMS architecture[2] will be modular to facilitate a phased implementation of the AMI system and other systems that are enabled by AMI (see Figure 1 below).

[1] In the instant application, the MDMS will be integrated with the CIS. The MDMS and/or RNI can provide data that can be used for the OMS but integration with the OMS would be filed under a separate project application.
[2] The MDMS architecture was developed with the assistance of Enspiria Solutions, Inc., HECO's AMI consultant.

[redacted]

Figure 1 – MDMS Architecture

MDMS - Integration with the CIS

The existing CIS receives meter data from multiple sources. Meter data collection is shown in the simplified diagram below (see **Figure 2**). For the first two systems, MVRS and Wishbone[3], data is obtained via handheld devices used by meter readers and field service representatives. At the end of the day, the handheld devices are placed in cradles and data is uploaded to the CIS. The Turtle[4] and MV-90[5] systems extract data directly from the meters over the power lines and phone lines respectively. The data routing for these existing systems is illustrated in **Figure 2**, below. For a limited number of meters, existing data can be generated in Itron HHF format and processed by MV-90; however, the MDMS will handle meter data in the AMI System.

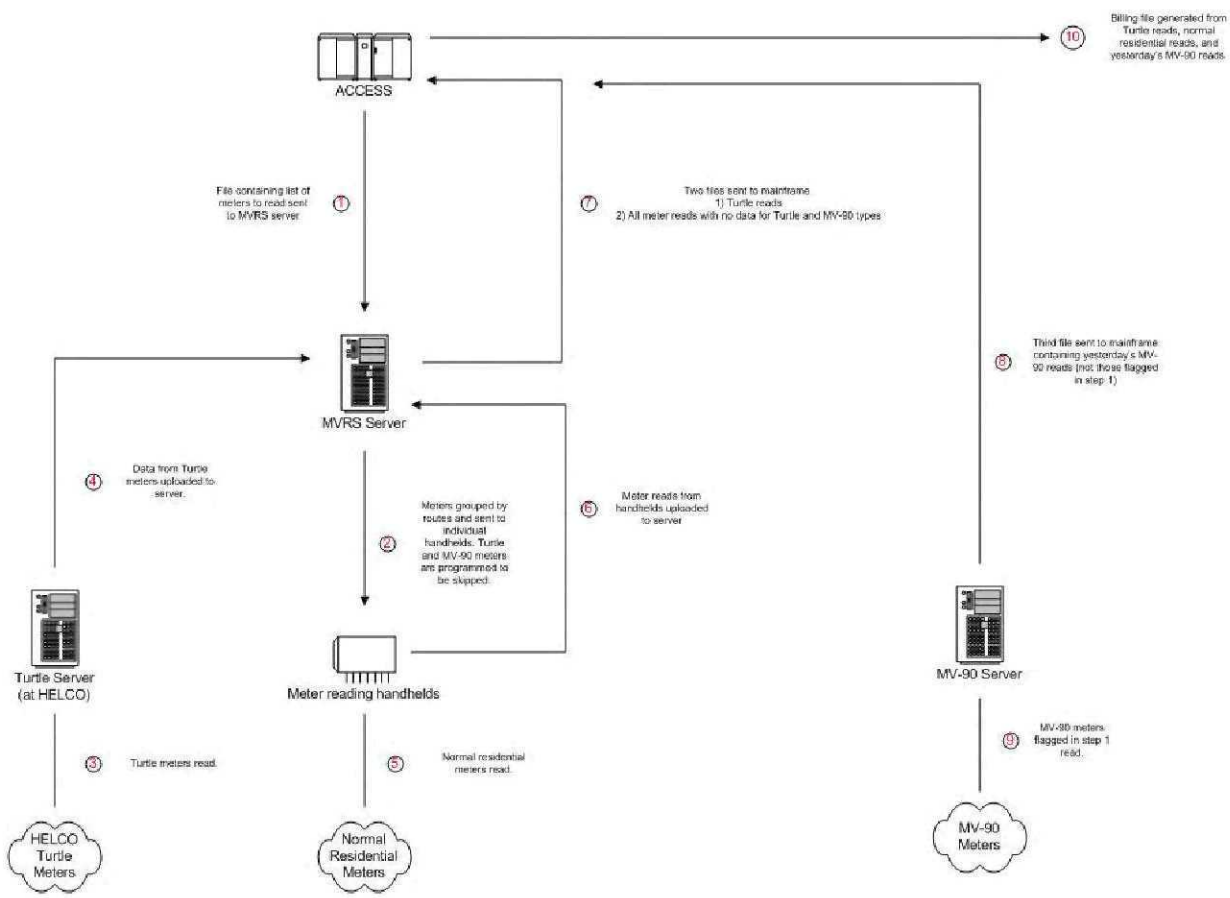


Figure 2 – Current Meter Reading Processes – Data Routing

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3 Wishbone is HECO's current work order management system.
4 Turtle is a low-speed Powerline Carrier (PLC) product from Hunt Technologies, Inc.
5 MV-90 is a software product from Itron, Inc.

HECO plans to implement the MDMS in the following three phases:

Phase I – Basic CIS and RNI Integration will provide full billing capability for existing rates and for additional TOU rates as required. In this phase, data from all the AMI meters will be routed from the RNI into the MDMS.

Phase II – Additional Integration Tasks to centralize more user functions within the MDMS and minimize actions that must be performed by users and system administrators manually or from within the RNI.

Phase III – Additional customization of the MDMS will be performed to redirect all existing Company metering systems (MVRS, MV90, and Turtle PLC) into the MDMS.

By dividing the MDMS implementation in this fashion, the benefits of the AMI project can be realized faster. The CIS will remain the system of record ("SOR") for billing-related data and customer information.[6] The MDMS will serve as the SOR for other data, as shown on pages 9 to 11.

Future MDMS Integration with Outage Management System (OMS)

After the OMS project went online on July 28, 2007, some AMI system functionalities that could support OMS were explored in 2008 using data captured by the Companies' limited population of AMI meters and Google Earth™ software.[7]

Figure 3 depicts a possible AMI and OMS configuration. In the outage management function, AMI would supplement the need for customer calls by sending out "last gasp" messages[8] to the OMS or MDMS. Without AMI, the utility relies on customers to manually report outages via phone calls to the Companies' Customer Service Representative ("CSR") or via the Companies' Integrated Voice Response ("IVR") system.

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[6] The definition of "SOR" is provided on pages 9 to 11. This document will be further refined during the MDMS development phase.
[7] See Figure 5 following.
[8] "Last Gasp" refers to the internal backup power of the AMI meter that allows the meter to send 3-5 messages when the meter experiences a power failure.

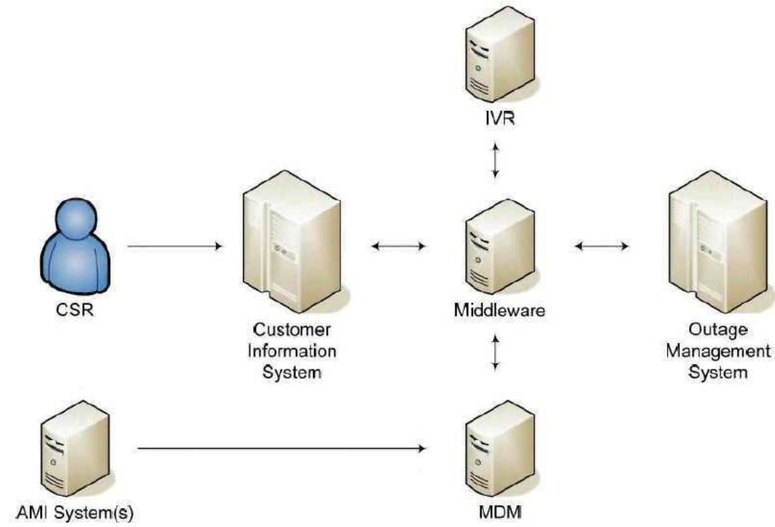


Figure 3 – MDMS to OMS Integration

A throttling mechanism between the AMI/MDMS servers and the Middleware system is also needed to manage outage reporting in certain situations. In the upper portion of **Figure 4**, the quantity of outage event notifications is limited by two factors: (1) the number of phone lines into the IVR; and (2) CSR resource capacity. Because such limitations do not exist with an automated AMI/MDMS link to the Middleware system, potential flooding of the Middleware with outage messages may occur, and this would negatively impact the OMS and CIS performance. For example, given an island wide blackout scenario, every AMI meter would attempt[9] to transmit a "last gasp" alert to the AMI/MDMS, unless steps are taken to throttle the alerts. One approach that is being studied is the use of so-called "canary meters" or fault circuit indicators ("FCIs") that are configured to provide outage notifications while other meters would be configured to suppress outage messages.

[9] It is estimated that approximately 20-30% of the "last gasp" messages will arrive at the FlexNet RNI; however, this is a large number of messages given the population of AMI meters that will be installed.

Oracle Utilities Network Management System is currently working to revamp its AMI interface package. This may provide a straightforward and economic route to MDMS-OMS integration in the future. HECO will investigate this further as this package becomes available.

HECO desires seamless interoperability between its large-scale systems. For example, when a customer service representative ("CSR") uses the new customer information system ("CIS") to check whether a customer has experienced a power failure, the information would be transparently provided by the MDMS and/or OMS. The OMS system could take advantage of AMI system alarms (power failure and restoration events) captured and stored in the MDMS and integrated with the utility's Geographical Information System ("GIS").

This concept is illustrated for Oahu, and more specifically, the Maile area in Figure 5 below, which shows remaining outages as red dots and restored areas with green dots. In the event of large scale outages, alarms can be efficiently filtered by the MDMS prior to routing to the OMS to manage information overload in the Companies' dispatch center.

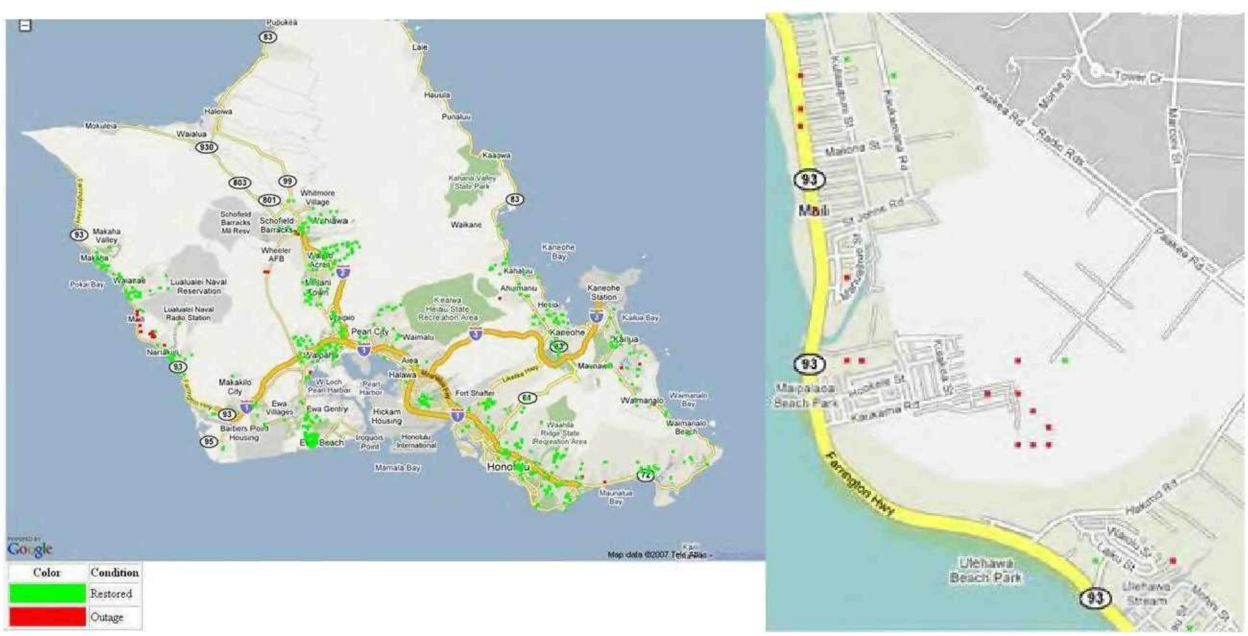


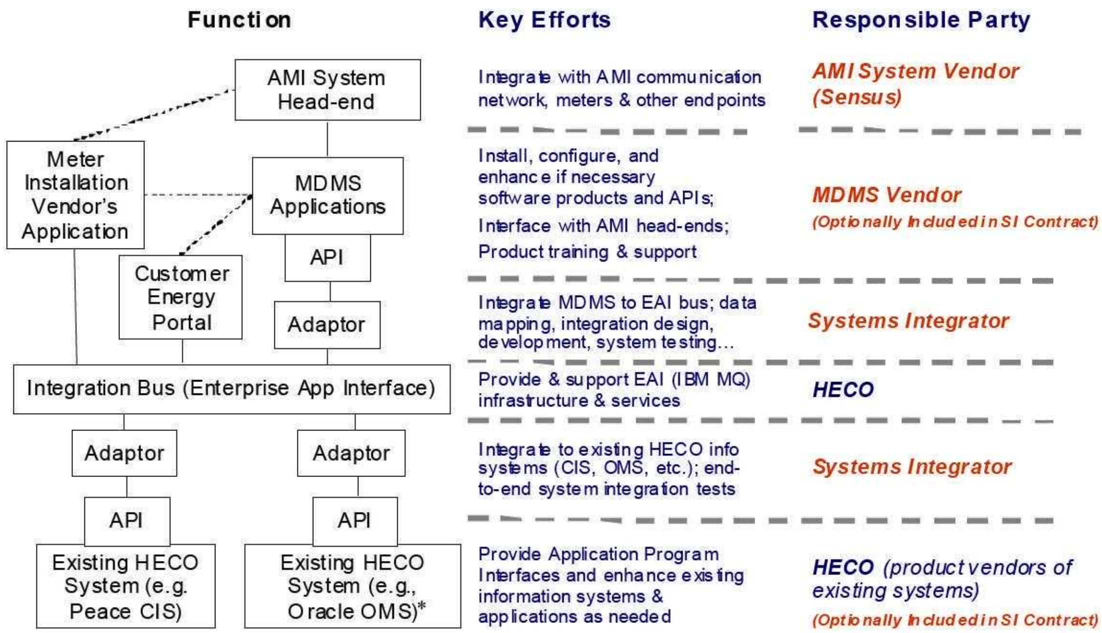
Figure 4 – Outage Management Example

Systems Integration

Based on experiences gained on recent enterprise IT projects and the Companies' IT Governance requirements, HECO plans to contract with an AMI Systems Integrator ("SI"). The Companies will retain a management consultant who will work with the Companies to develop a Request For Proposal ("RFP") package, review bids, interview prospective SIs, and assist with proposal evaluations. The selected SI will be responsible for the delivery of a fully functional MDMS system, including all necessary integrations. In this role as a prime contractor, the cost of the SI will be higher and the Companies' have added a risk premium to the MDMS base cost that was developed in conjunction with the Companies' AMI consultant[10].

Figure 1 delineates the roles and responsibilities of HECO, the Systems Integrator, AMI vendor, MDMS vendor, and existing HECO software systems (CIS), as well as the points of demarcation for each party.

[10] Enspiria Solutions, Inc.



*OMS integration is not included in the AMI Project but will be looked at in the future.

Figure 1 – Systems Integration

System of Record
(Preliminary)

	CIS (Peace)	MDMS (TBD)	AMI Head-end (e.g. RNI, MV90, Turtle)	DR/Load Mgmt Sys (Yukon)	GIS (Intergraph)	WMS (Ellipse)	OMS (Oracle SPL)
Customer account, prices & rates	– All (premise location, active / inactive, rate, meter, etc.) – Rates, rate definitions (TOU buckets, CPR…) – Bill cycle schedule – Connect/ disconnect – Price – DR program enrollments	– *All (premise location, active / inactive, rate, meter, etc.)* – *Rate definitions* – *Bill cycle schedule* – *Connect/disconnect states* – *DR program enrollments* – *Price change event* – *DR events*		– *DR program enrollments* – *DR events*	–	–	–
Meter assets & asset data	– Inventory – Installation state (installed location, returned, etc.) – Meter type, hard configuration – Remote disconnect/ reconnect capability – Service orders – Test results – Installation & service history – Reading system (AMI, MVRS, etc.)	– *Installation state (installed location, returned, etc.)* – *Meter type, hard configuration* – Soft/ firmware configuration (interval length, outage & voltage filter, etc.) setting history – Operating states (communication, billing ready…) – Diagnostics & event log	– Comm path, dial-up #, protocols, etc. – *Diagnostics (pass through)* – Current soft/ firmware configuration (interval length, outage & voltage filter, etc.)	–	–	–	–

	CIS (Peace)	MDMS (TBD)	AMI Head-end (e.g. RNI, MV90, Turtle)	DR/Load Mgmt Sys (Yukon)	GIS (Intergraph)	WMS (Ellipse)	OMS (Oracle SPL)
AMI network infrastructure equipment, assets and health		– Performance, availability and accuracy of meter read and event data	– Hardware, firmware, software versioning – Performance and availability – System diagnostics	–	– Asset data, asset locations (Note: HECO needs to decide which organization will maintain this data.)	– Work orders on AMI network equipment (not meters)	–
Meter read for billing	– Determinants used for billing (CUM consumption, TOU consumption, LF, CPR credit, etc.) – Billing determinants estimation, edits, versioning & history – Billing determinant source (MV-RS, MDMS, Turtle, etc.)	– Determinants sent for billing – Determinant to register/interval data audit trail – Determinants flagged as "actual, estimated, or edited" (business rule TBD) – Interval data reads – Interval data estimation, edits, version & history – *Billing determinant source (MV-RS or MDMS) (pass through only)*	– *Register and interval data reads (pass through only)*	–	–	–	–
Meter read for system engineering & operations	– Customer trouble calls – *Transformer loads*	– Meter outage & restoration events & history – Virtual meter loads – Meter voltage, blink counts, etc.	– *Meter outage & restoration, voltage hi/lo events (pass through only)*	–	– Virtual meters by connectivit y – *Virtual meter loads*	–	– Outages – Outage statistics

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	CIS (Peace)	MDMS (TBD)	AMI Head-end (e.g. RNI, MV90, Turtle)	DR/Load Mgmt Sys (Yukon)	GIS (Intergraph)	WMS (Ellipse)	OMS (Oracle SPL)
Meter read data for load research	– Customer rate change events	– Virtual meter points (manually created by Load Research staff) – Interval load usages at virtual meter points	–	– Demand Response events	–	–	–
DR devices (e.g. P.C. Thermostat, Load Control Switch, in-home display, etc.)	– Inventory – Installation state (installed, returned, etc.) – Device type, hard configuration – Test results – Installation & service history	– *Installation state* – *Op states* – *DR event history*	– Comm path – Diagnostics – Software/ firmware configuration	– *Soft/ firmware configuration* – Software & firmware configuration history – Current events and op states – Event history – Diagnostics & history	–	–	–

Exhibit 10 contains confidential information and will be provided

after a Protective Order is issued in this proceeding.

FlexNet AMI Network Details

The AMI communications network to be provided by Sensus is known as FlexNet. FlexNet is a robust communications system designed to maximize service area coverage while minimizing infrastructure hardware requirements. As illustrated in figure 1 below, in addition to AMI meters, an AMI network is divided into two elements: (1) the Tower Gateway Basestations ("TGB"), and (2) the Regional Network Interface ("RNI").

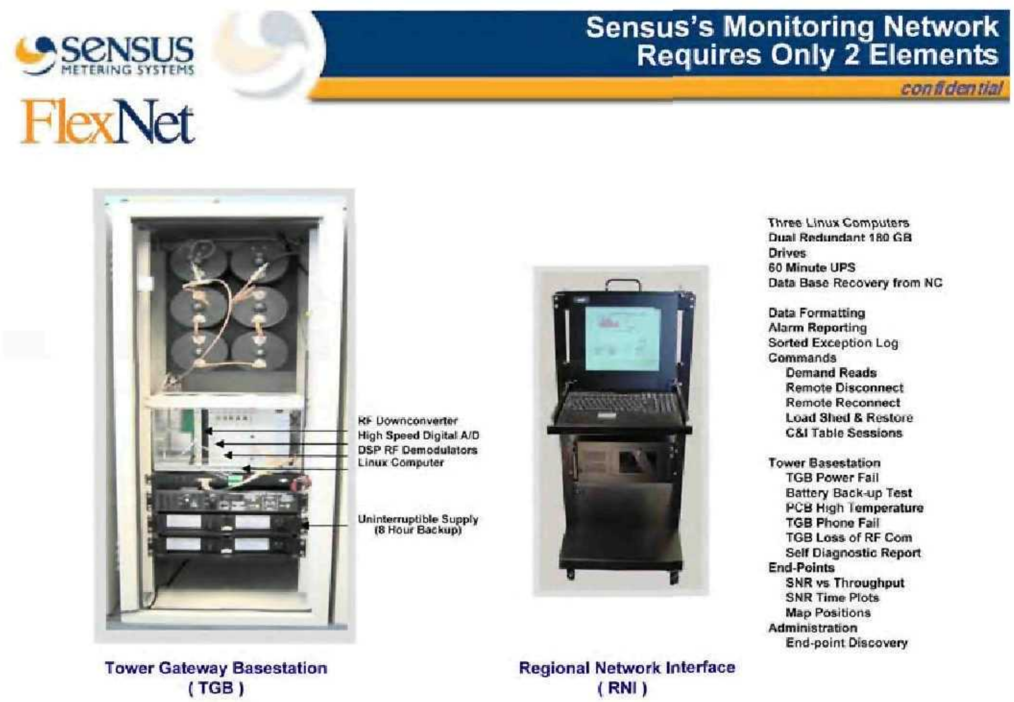

Figure 1: AMI Network Elements

FlexNet employs a licensed frequency band (centered at 900 MHz) and has several modes of communication, depending on the information being transmitted and the capability of the end device. Figures 2-5, below, were provided to the Companies by Sensus and illustrate FlexNet's modes of communication.

SENSUS METERING SYSTEMS — Simplicity Flexibility Reliability — confidential

FlexNet

The FlexNet System has 3 Modes of Communications

1) Scheduled ALOHA hourly/ daily meter read messages and bulk status information
- Generally required on a daily basis (Normal Mode 111 ms, Boost Mode 1024 ms)
- 20 Tower Receivers can read 1.4 million hourly meters (see "ALOHA Calculator" for capacity)

2) Real time, report-by-exception, status and alarm information
- Generally required in seconds or minutes (Priority Channel 77.6 ms)
- a) Power available (240 VAC or battery)
  - Alarms reported immediately
  - Reported redundantly (programmable 1 to 32 times or until Acknowledged by tower)
- b) Power not available (limited to capacitive supply)
  - 3 - 6 redundant transmissions occur in dilated time intervals
  - 30 sec Avg initial message report (See "Power Outage & Restoral Reporting Reliability")
  - Faster reporting intervals can be selected, application dependent

3) Poll-Respond message traffic
- Generally required in real time (Poll 158 ms/ Respond 111 ms, 50 bytes)
- C&I meter traffic, Demand reads
- SCADA / Distribution Automation

Figure 2

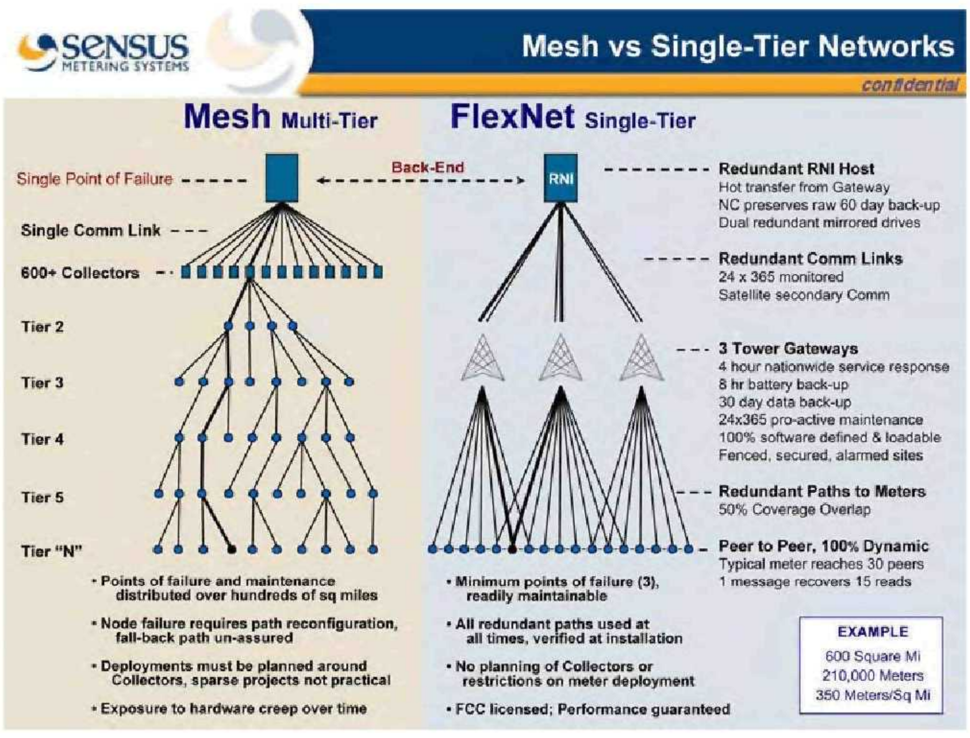

Figure 3

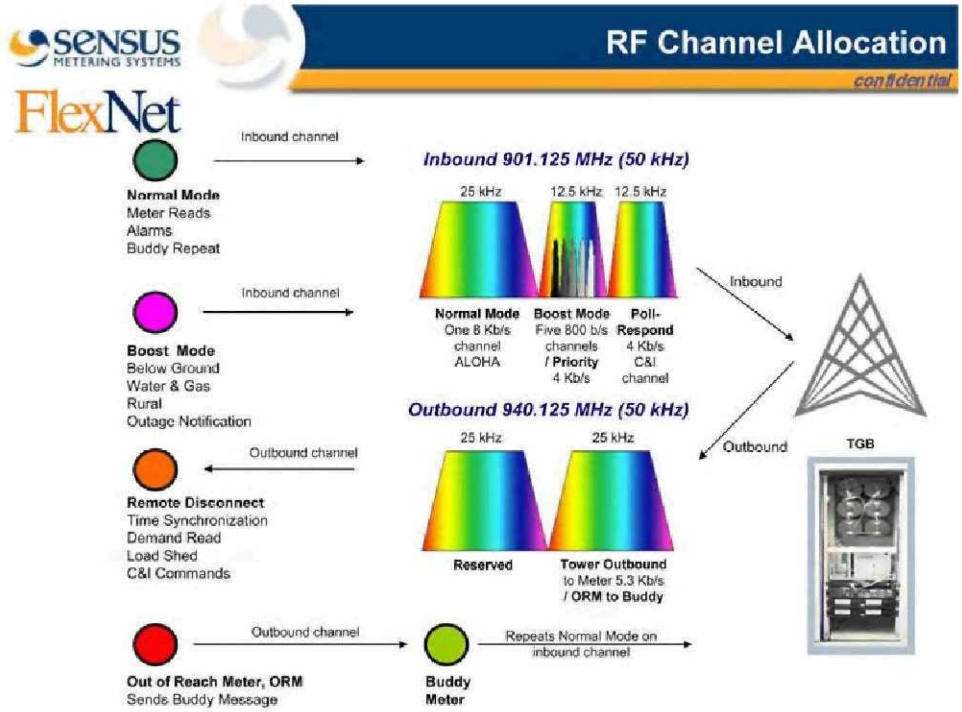

Figure 4

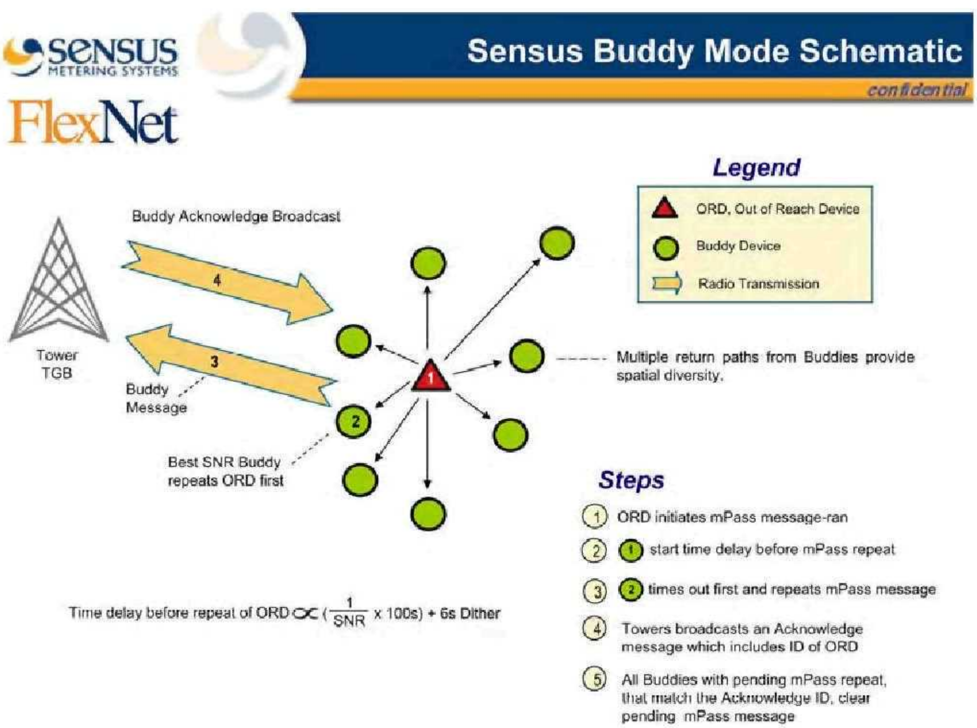

Figure 5

Within the FlexNet network, incoming messages (meter to the TGB) are communicated to the TGB tower sites via one of the following modes:

- **Normal Communication Mode:** Direct communication from the end device (meter) to the TGB;
- **Message Pass (mpass) Communication Mode:** Indirect communication through a "buddy" device such as another AMI meter or a FlexNet Network Portal ("FNP") repeater device; and
- **High priority (Boost) Communication Mode:** High Priority communication directly from the end device to the TGB.

Outgoing Messages (TGB to the meter) are communicated via the mpass communication mode. The RNI continuously monitors and records operational statistics and metrics for each communication node and uses that information to tune its communication mode and frequency for the optimal level of performance.

The placement of TGBs in the FlexNet network design ensures overlapping coverage in order to achieve signal redundancy. This coverage is shown in Figure 6 below.

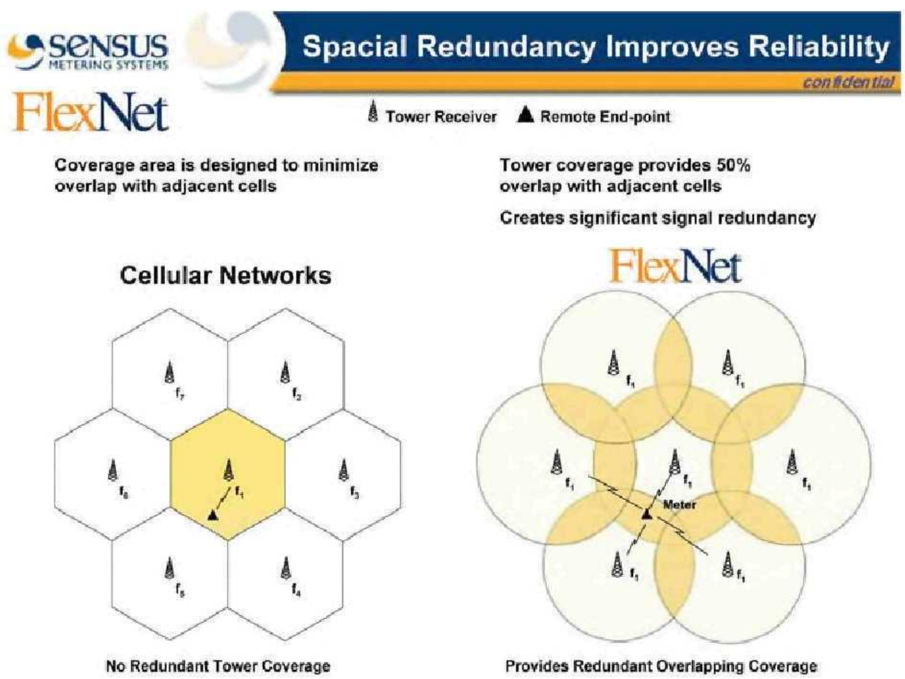

Figure 6

The use of tall tower sites (typically 200' to 600') and the unique FlexNet communications technology minimizes the cost of the network infrastructure due to a relatively small number of TGB sites. Figures 7 and 8 below provide details regarding the range and coverage of Sensus' FlexNet communications technology.

SENSUS METERING SYSTEMS
FlexNet

Sensus's Range and Coverage Over Cellular
confidential

GREATER RANGE	
Higher Power Output End-point 250 mW vs. 1W	6 dB
Greater Sensitivity (BW and Modulation)	3-13 dB
Sensus Not Self-Noise Limited	2-10 db
MACRO DIVERSITY	10-15 dB
CELLULAR CAN'T REPEAT A VOICE MESSAGE 5 TIMES OVER 20 HOURS	
BOOST MODE CAN BE USED ON UP TO 40% OF WEAK END-POINTS	10 dB
MESSAGE PASS MODE, 2-WAY END-POINTS HAVE TRANSPARENT, SELF-CONFIGURING REPEAT MODE	136 dB

Note: 9-12 dB Doubles Range at 900 MHz

Figure 7

SENSUS METERING SYSTEMS
FlexNet

Four Components of Range
confidential

	SENSUS	CONVENTIONAL AMR
1) Antenna Height	200' to 600'	4' to 20'
2) Transmit Power	2 Watts	1mW to 500 mW
3) Sensitivity	-130 dBm	-100 dBm to -110 dBm
4) In-Band Noise	1-3 dB typ	10 dB to 40 dB

EVERY 10 dB DOUBLES RANGE FROM 200' TOWER

Figure 8

The typical range for a single TGB is 15 miles, and the network design is based on achieving overlap coverage ratio of approximately 1.5. In other words, the meters generally have access to more than one TGB site. Sensus' network design calls for 25 TGBs. Oahu, Maui, and the Big Island would have 15, 3, and 7 TGB sites respectively. TGB coverage maps for Oahu, Maui, and the Big Island were developed in 2008 based on Sensus RF Propagation studies and AiR[1] network traffic modeling. These maps are provided as figures Figures 9-11 below.

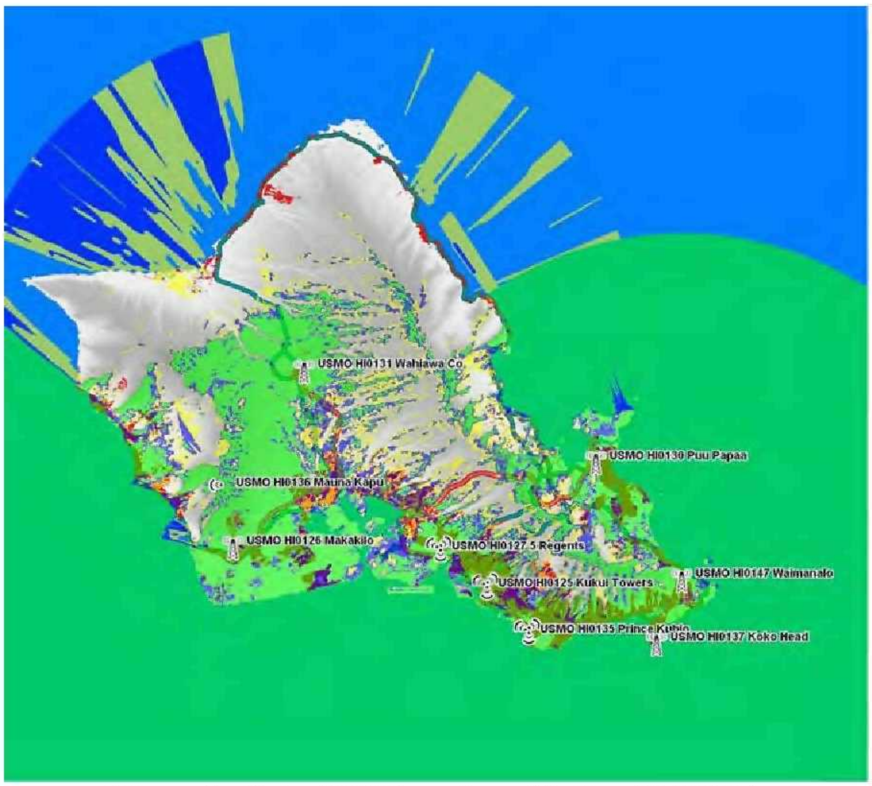

Figure 9: Oahu TGB Locations (9 sites, 15 TGBs)

[1] AiR denotes Sensus' Aloha iAbort RF model. Aloha is a network model developed at the University of Hawaii that describes the probability that a message from one network node will collide with another when it transmits if the transmission times are randomly distributed. There are two types of Aloha networks, slotted and non-slotted. The basic difference is that slotted networks will always receive at least one of the two messages if there is a collision. With non-slotted networks, both are lost. The FlexNet system performs as well or better than a slotted Aloha network because of the iAbort algorithm in the TGB. iAbort means Intelligent Abort, which essentially means that if the system is receiving a weak signal and a second, a stronger signal comes in; the system automatically "aborts" reception of the weaker message and demodulates the stronger one. The goal is that another TGB is also listening to the weaker signal, which, since it is closer, identifies it as a strong signal and demodulates it. The result is that the RNI gets both messages even though the two messages transmitted at the same time.

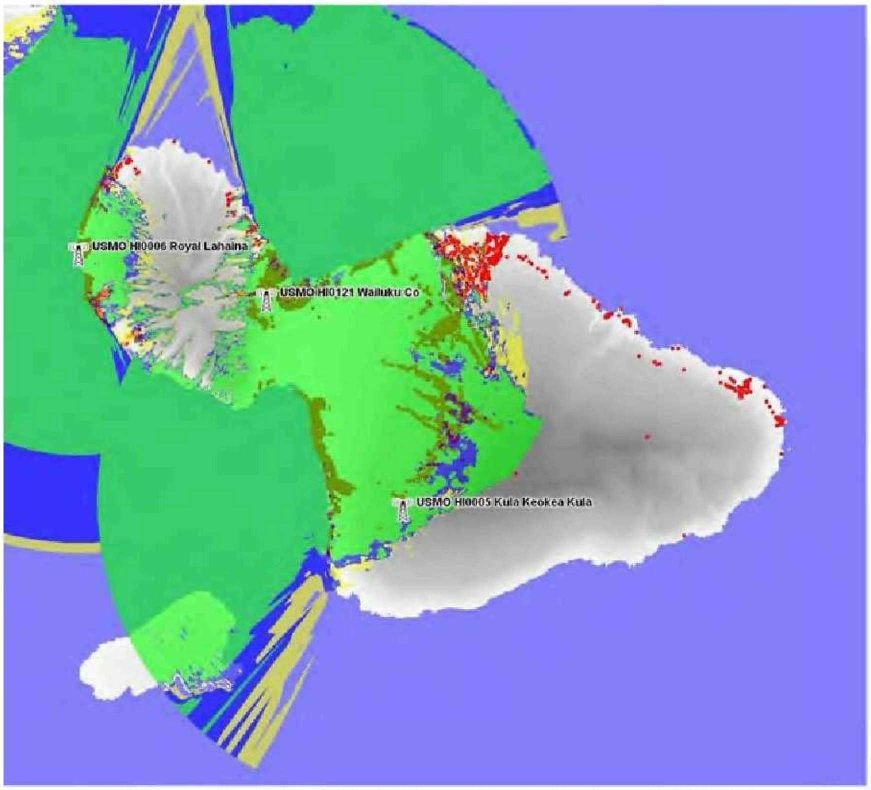

Figure 10: Maui TGB Locations (3 sites, 3 TGBs)

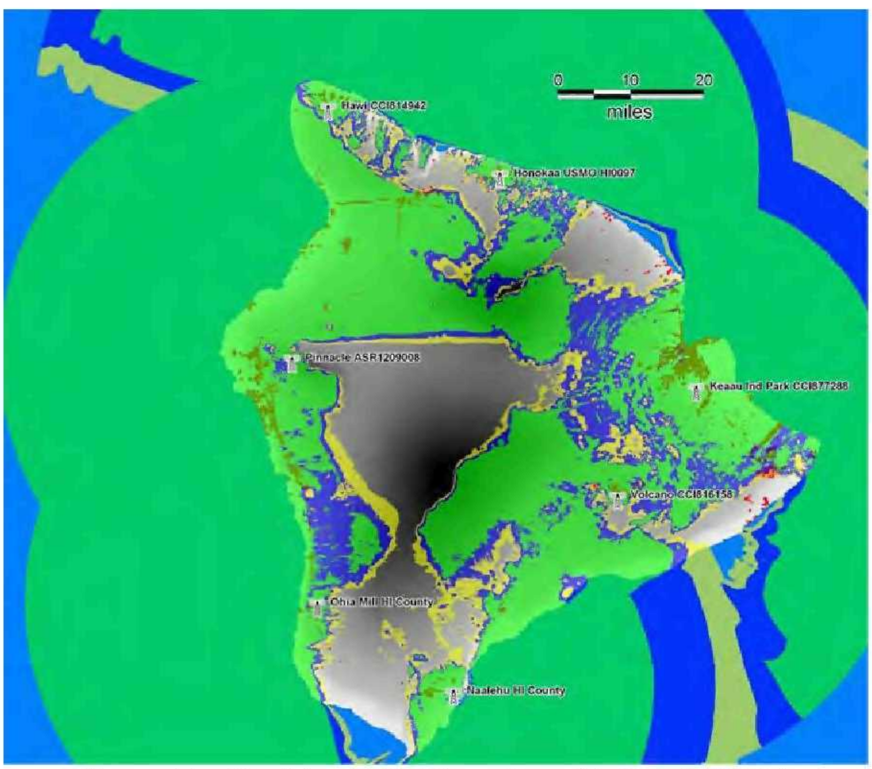

Figure 11: Big Island TGB Locations (7 sites, 7 TGBs)

Typical characteristics and benefits of the FlexNet system include:

- Communication over a licensed frequency
- Non-susceptibility to legal interference
- High power
- Typical antenna heights of 200' to 400'
- Long range (up to 15 miles)
- Excellent building penetration
- Tower-based 2-way systems
- Upgradeability to remote firmware
- Direct connection from device to tower
- Use of commercially available single-chip transceiver (> 1 million fielded)
- Protocol field proven over 8 years
- 2 Watt transmit power
- 130 dBm Sensitivity

<u>Buddy Communications or "mpass" Mode (FNPs and FRPs)</u>

If a meter cannot communicate directly with a TGB, the message can be relayed by a "Buddy Meter" to the TGB via the mpass channel. If a Buddy Meter site is not available, a FlexNet Network Portal ("FNP") can be installed to relay the message directly to the TGB or a FlexNet Remote Portal ("FRP") can be used to relay the message directly to the RNI through an Internet backhaul. A FNP is depicted in Figure 12 and the FRP is shown in Figure 13 below.

<u>FNP</u>

Figure 12: FNP

The FNP is a transceiver unit that provides simple "store and forward" messaging from Sensus AMI meters. FNPs can be strategically placed after the complete deployment of the TGBs and network coverage is evaluated. The FNP provides an economical solution[2] within an existing network. Messages are collected at the FNP and transmitted to one or more TGBs over the primary licensed frequency to assure that satisfactory coverage is provided within a designated service territory.

A single FNP can typically support up to 400 AMI meters within a serviceable range of an installed network. RF transmissions on the primary licensed frequency allow the FNP to receive and transmit messages from AMI meters to one or more TGBs. By incorporating RF transmission as the backhaul communications method, the FNP provides the Companies with greater installation flexibility. Ubiquitous locations such as light poles, buildings or existing

[2] FNPs are much cheaper and more convenient to install than TGBs. FNPs can be mounted on the companies' utility poles, communication sites, or other appropriate facilities.

utility structures with access to AC power (110-240 VAC) provide excellent candidate locations for FNP installations. Flexible antenna options can also be utilized to maximize performance and the FNP incorporates a battery back up power source to ride through limited duration power outages, which increases FlexNet system reliability.

<u>FRP</u>

Figure 13

- The FRP provides TGB functionality with the RF characteristics of the FNP. Cellular or Ethernet (fiber, cable, DSL) can be used for backhaul from the FRP. The FRP can accommodate approximately 2,000 endpoints, includes 2-4 hour battery backup, and provides 3-5 square mile RF coverage. As with the FNP, ubiquitous locations such as light poles, buildings or existing utility structures with access to AC power (110-240 VAC) provide excellent candidate locations for FRP installations. Locations with a wired Ethernet point are useful; however, the FRP is designed to operate with integral cellular transceivers.

RNI

The RNI is the network backbone of the AMI system. It receives and stores all meter data transmitted to the TGB(s), monitors the system health and communications statistics of the TGB(s), and maintain a 60-day log of meter data. The RNI provides network capacity for all of the TGBs in the Companies' local RF networks.

The RNI consists of multiple servers, which provide the following functionality:

Database Server
- Utility meter read data
- Information to manage the AMI network
- Web reporting data

Statistics Server
- Network communication statistics from AMI meters and TGBs
- Meter and TGB graphs

Web Server
- Website/User Interface
- Site LDAP[3] (Java Open Single Sign On)
- System monitoring scripts (Perl[4])
- Auto-generated emails for operations
- File transfers (Total Meters, Demand Resets, XML[5] Meter reads)

Network Controller (NC) Server
- NC programs
- Java engine bundle
- Postgres[6] tools data

Map Server
- ka-Map[7] geospatial data

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[3] LDAP, Lightweight Directory Access Protocol, is an Internet protocol that email and other programs use to look up information from a server.

[4] Perl is a dynamic programming language created by Larry Wall and first released in 1987.

[5] XML or Extensible Markup Language is a general-purpose specification for creating custom markup languages. Its primary purpose is to facilitate the sharing of structured data across different information systems, particularly via the Internet, and it is used both to encode documents and to serialize data.

[6] Postgres (or PostgreSQL) is an open-source, object-relational database management system.

[7] ka-Map is an open source project that is aimed at providing a Javascript API for developing highly interactive web-mapping interfaces using features available in modern web browsers.

The logical architecture of the RNI is shown in Figure 14 below:

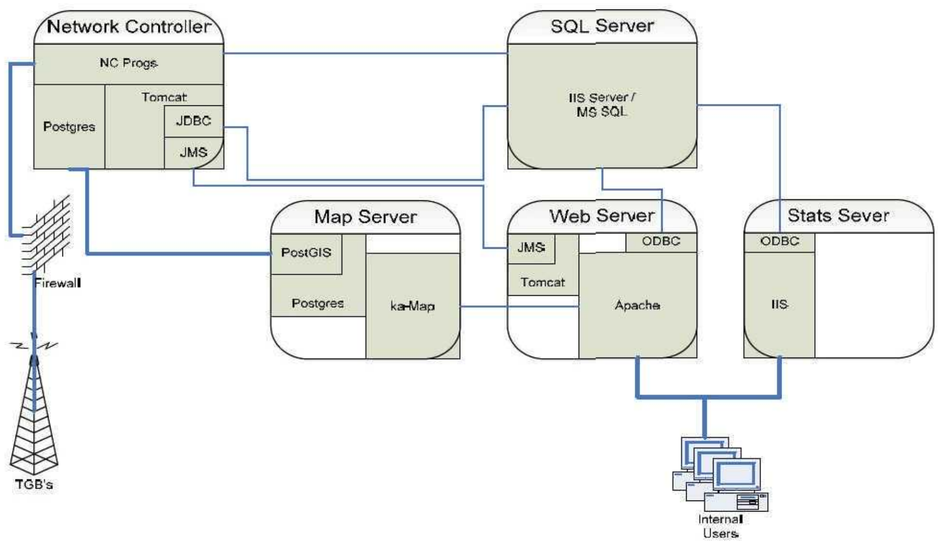
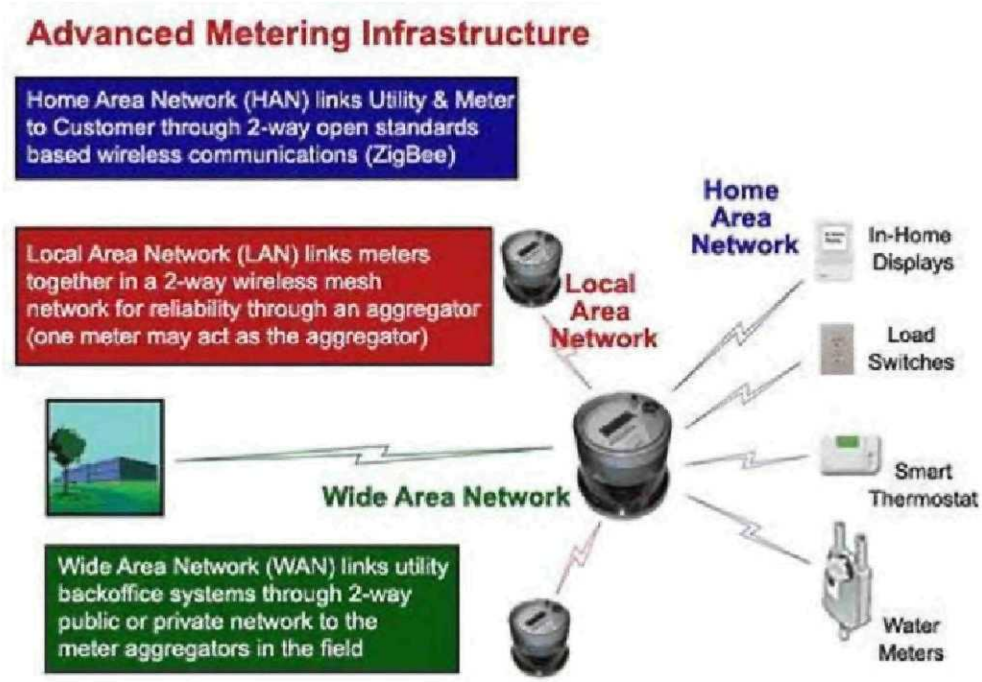


Figure 14: RNI Logical Architecture

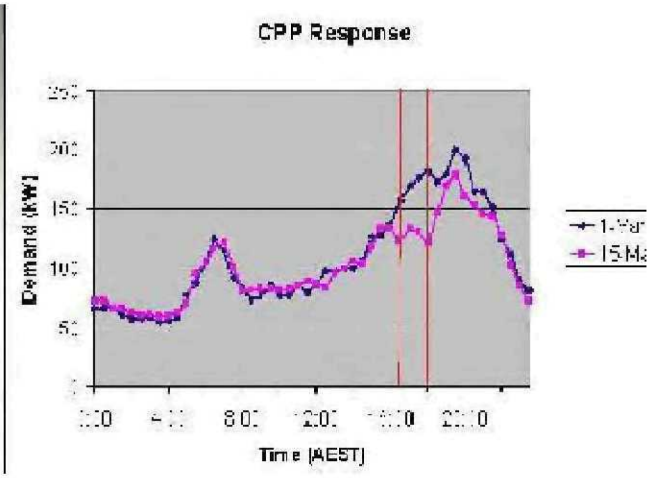
HANs and In-Premise Displays

The role of a Home Area Network ("HAN") in an AMI system is illustrated by the diagram below. Additional details regarding HANs are provided in Exhibit 13 (Sensus Demand Response and Smart Grid White Paper):

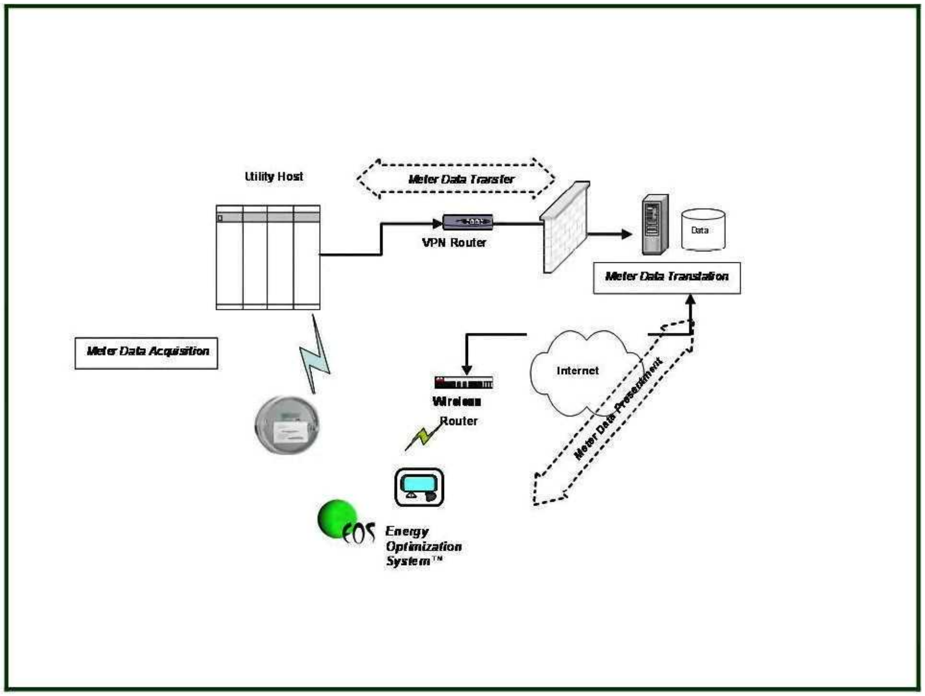


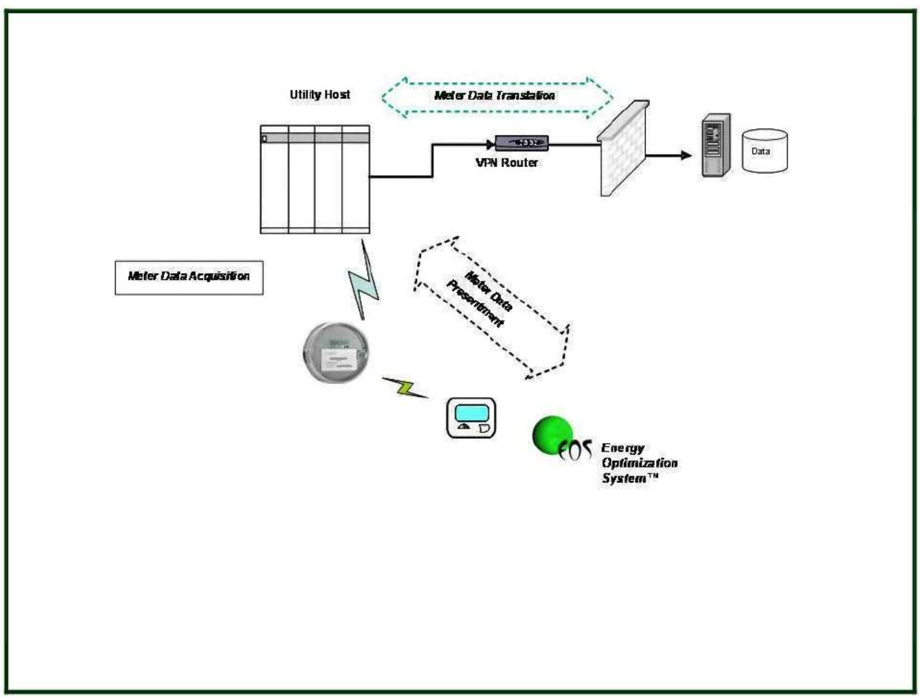
<u>See</u> Brad Smith, <u>ZigBee Generates Power</u>, Wireless Week, July 15, 2007.

The following example of an in-premise display's role in a HAN was provided by Ampy Metering (Bayard Investment Group):



The following examples were provided by Widefield Technologies and illustrate how HANs can be employed to provide electricity consumption information and other information to an in-premise display:



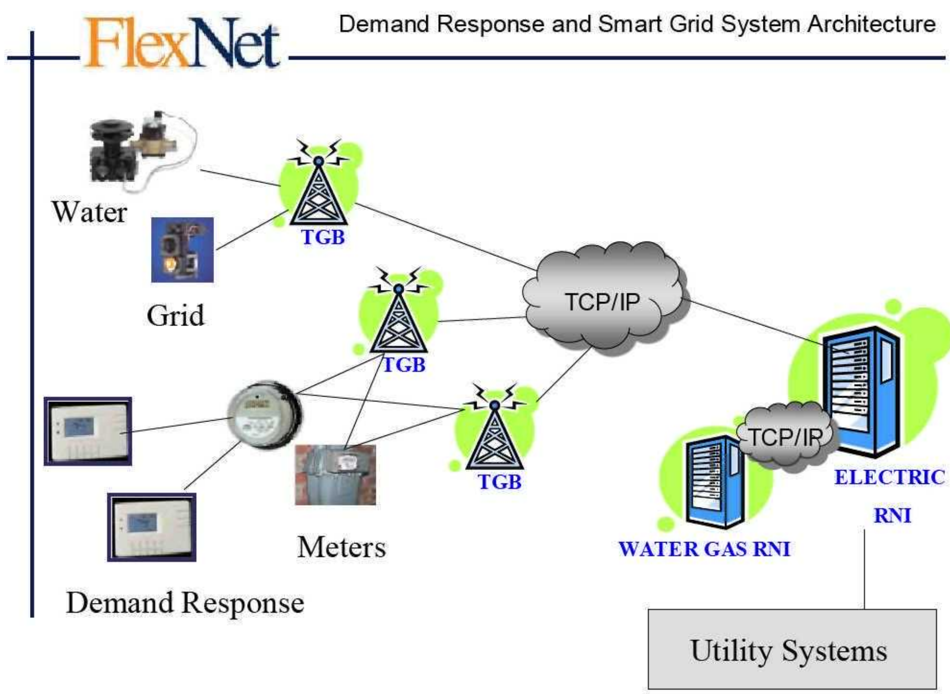


Sensus Demand Response and Smart Grid White Paper

February 26, 2008

Introduction

As a natural progression of Sensus' FlexNet Advanced Metering Infrastructure (AMI) system solution, Sensus is actively architecting end-to-end demand response and Smart Grid solutions that operate over the FlexNet two-way licensed band RF solution and integrate with demand response and peak pricing applications. This whitepaper describes the applications, Sensus' architecture and key functional requirements to implement those solutions.



Background

Nationwide, an increasing number of regulatory policy directives are playing a key role in encouraging utilities to deploy AMI systems that provide customers with more detailed energy consumption information and demand-reduction capabilities.

Many IOU[1] customers have existing air-conditioning load management (ACLM) and load shed programs operating on legacy networks; predominantly one-way paging systems from vendors such as Comverge, Cannon, and CSE. Commensurate with their adoption of the Sensus

[1] Investor owned utilities.

FlexNet two-way AMI solution, the utilities need a clear path to transition from one-way systems to the newly adopted two-way solutions.

Multiple, emerging and competing technology standards for home area networks (HANs) like Z-Wave, LonWorks, HomePlug, ZigBee, 6LoWPAN and others have added both promise and confusion to the arena. Utilities are searching for flexibility to achieve AMI cost savings from two-way fixed-base metering today, while maintaining flexible options to implement emerging standards in the future.

Given the uncertainty surrounding the future standards, utilities and consultants are banding together in various forms to adopt common architecture approaches that provide safety in numbers for the utilities and a crisp roadmap for the vendors.

Target Demand Response Applications

Based on market feedback from major IOUs across the United States and Canada, the Sensus FlexNet demand response applications will initially cover two main categories of use. 1) Applications which involve customer interaction and approval and 2) Applications mandated by the utility.

Customer Interaction

A major benefit of the Sensus FlexNet AMI solution is that it provides the underlying two-way communications solution to deliver a higher level of customer awareness regarding electricity pricing, consumption, time-of-use, rate tiers and voluntary load reduction program events. With increased electricity demand on the grid which may result in generation shortfalls, the need for utilities to reduce energy demand in support of grid stability is paramount. FlexNet will help facilitate load reduction at the customer's site by communicating instantaneous kWh pricing and voluntary load reduction program events to the customer and to various enabling devices connected to FlexNet either directly or through a Home Area Network (HAN) Voluntary load reduction events may be scheduled with a large amount of advanced notice (24 hrs) or near real-time. For the utility to receive the desired customer response, FlexNet demand response and Smart Grid solutions will provide customers with timely pricing, event and usage information.

End customer responses delivered via the two-way FlexNet network will be used to determine 1) how and/or if consumers have responded to a pricing event, 2) if the utility needs to launch other demand response events to achieve the needed demand reduction and 3) assist the utility in determining how to structure future voluntary load reduction programs.

FlexNet demand response solutions provide the utility with a variety of flexible mechanisms to distribute price signals and voluntary load reduction events to customers, including the ability to display current pricing and voluntary load reduction event information within the customer's home/business. FlexNet can reliably initiate automatic load reduction at the customer's site by communicating event and pricing information to customer equipment and the customer's equipment will respond to the utility's or the customer's predefined setting. Should the utility desire customer intervention, the consumer will be able to opt-out of utility load reduction requests with a device within their home/business.

Utility Mandated

Mandatory load and energy management applications are dispatched by the utility for reliability purposes. These events are mandatory due to the potential of the demand for power exceeding supply as a result of unexpected power plants going offline or congestion in transmission and/or distribution lines. The customer may be (1) enrolled in or (2) as condition of service be defaulted on a mandatory demand response program used for grid management. For voluntary enrollment in a utility's program, the customer is generally compensated with a credit on their monthly bill.

Typical devices controlled in mandated applications may include programmable thermostats, air conditioners, water heaters, pool pumps, etc. Programmable communicating thermostats (PCTs) can act as both a load shedding and passive/informational device through its built-in display.

Mandatory load and energy management events may not provide customers the option to override the load shed request. The utility may rely on a firm load shed to avert rotating outages. Giving customers the option to override a mandatory load shed request increases the possibility of a complete power outage. For public safety purposes, the utility must also be able to immediately remove a customer off the program due to a medical emergency and restore operation, for example, to an air-conditioning system as soon as possible.

FlexNet Functional Capability System Components

Future Sensus FlexNet demand response and Smart Grid product offerings consist of several components that work in combination to deliver an end-to-end solution that provides the utility with flexible, future-proof options over the 15- to 20 year time horizon of the FlexNet AMI platform. Those components include the following:

- ❑ Utility Operator Applications
- ❑ Two-way Communications
- ❑ 256 AES[2] Security

[2] A commonly employed communications encryption method is the "Data Encryption Standard" (DES). DES works by encrypting data with a 56-bit long key. Triple DES (3DES) is an enhancement to DES that effectively runs 112-bit long keys. DES and 3DES are both widely used in commercial and non-defense government communications today. To provide a higher degree of security than both DES and 3DES, a new standard called Advanced Encryption Standard (AES) has been developed. The new AES standard with 128-bit keys has been approved by the U.S. Government to protect sensitive, unclassified data and will replace the use of 3DES.

- ❑ Best of Breed Performance and Reliability Characteristics
- ❑ Endpoint Devices

Utility Operator Applications provide the user interface for the underlying technical solution. The demand response and Smart Grid applications will integrate with the functionality of the Sensus head end system (RNI). Sensus is currently pursuing multiple "make/buy/partner" decisions with regard to a demand response and Smart Grid application suite. In all cases, the application will have one or more of the following characteristics: Control, Measurement & Monitor, and Consumer Interface.

Control applications respond to control signals. The simplest control application is direct control, which turns loads on or off. Control applications can also cycle, which means they turn the load on and off at configurable time intervals. Additionally, more sophisticated control applications would limit the load of an appliance based on configurable thresholds.

Measurement and Monitor applications provide internal data and status. Applications can be as simple as a thermostat that measures and monitors the environmental state such as temperature and provide "on/off" control of appliances or equipment. More complex monitoring can also be provided such as 1) distributed generation functionality where local energy input and output is measured and monitored or 2) sub-metering functionality where FlexNet measures and monitors device-specific consumption or production. A Plug-in Hybrid Electric Vehicle ("PHEV"), for example, can have sub-metering functionality as well as distributed generation.

Sensus anticipates that utilities and consumers will gradually implement distributed generation systems (small-scale power generation technologies) to provide an alternative to or an enhancement of the traditional electric power system. As more homes and business become "green", it is anticipated that the utility will need to support distributed generation sources such as solar panels, small wind turbines, or PHEVs that may discharge back into the network. Sensus FlexNet is limited to electric meter application. In fact, information can be shared with gas and water meters and propagated through the AMI network and transferred to the appropriate entity. As an example, FlexNet already supports the ability for an electric utility to gather water meter information and pass that information to the water utility.

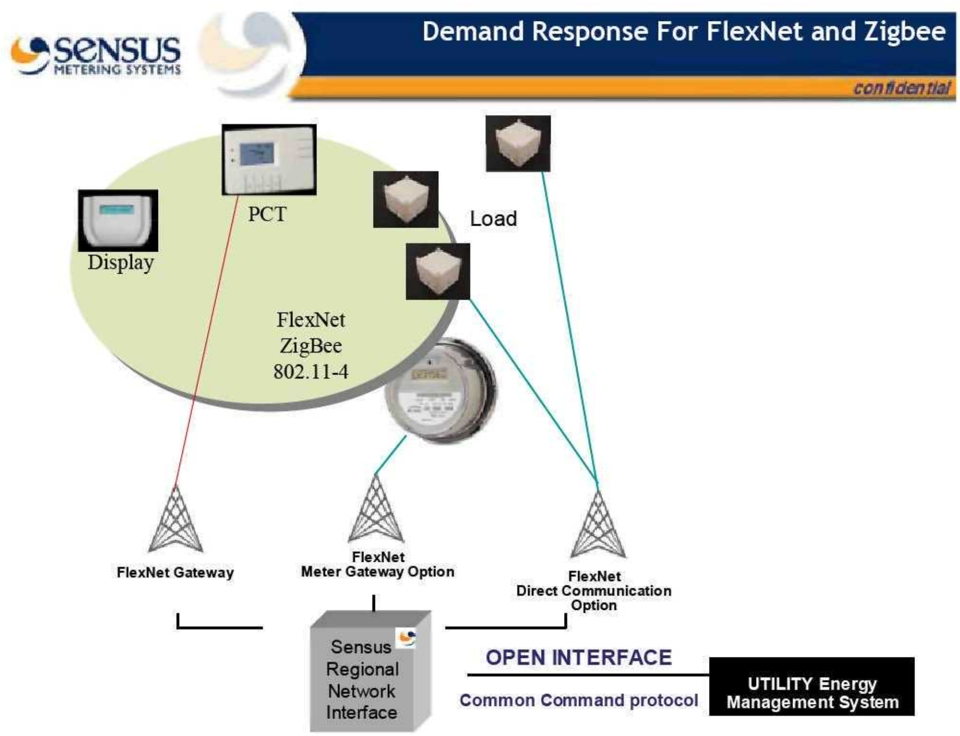
Consumer Interface – Depending on the regulatory environment and the marketing strategy of the utility, some applications may require a consumer interface to provide local user input or receipt of information. These applications are based on the data type.

- User Input - Provides consumers with a means to input data (using a keypad or button)
- User Receipt - Provides an application with a means to send data to the consumer (such as through a graphical or text display or a text message)

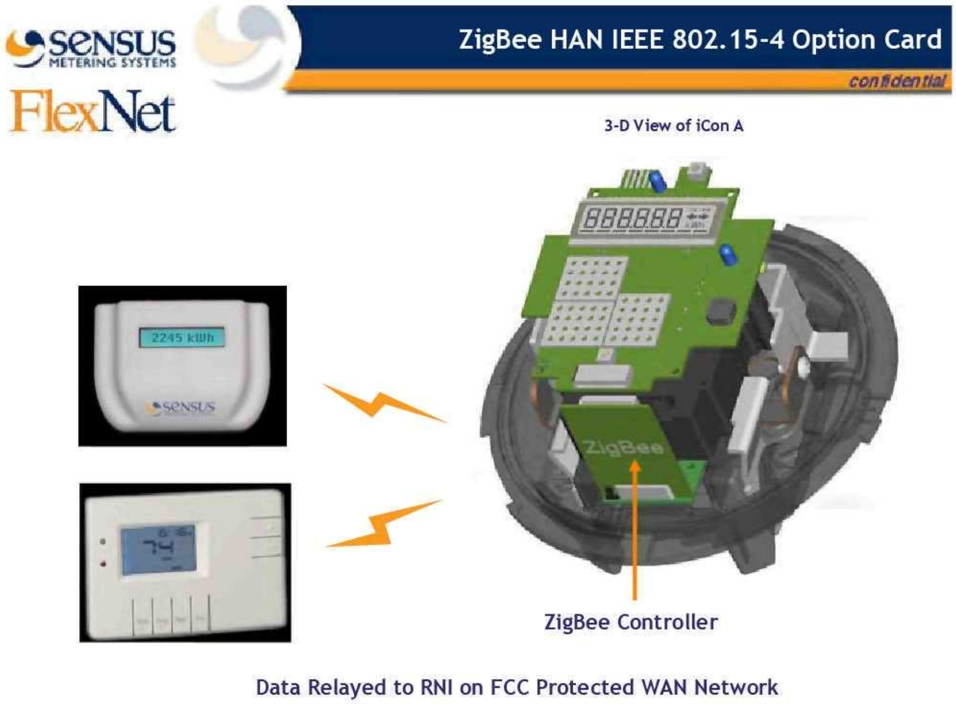
One of the main arguments for energy conservation is a better informed consumer. With more timely and detailed information at the hands of the consumer, they will be able to make better choices about energy usage and conservation. With direct data access, the consumer does not need to wait until the end of the month to see how changes in their usage have affected their bills, and with energy usage profiled in smaller increments, the consumer can see the impact of changing their own energy usage patterns.

Two way communications is provided by the FlexNet system from the RNI at the utility to the endpoint at the consumer or in the Smart Grid. Some applications on the network (water meters, selected Smart Grid devices) may be battery operated and support only one-way communications. For consumer and industrial demand response applications, Sensus will initially support several two-way HAN architectures, FlexNet and ZigBee.

Using the FlexNet HAN, broadcast commands may be sent through the electric meter at the customer premise or directly to the FlexNet device. In the ZigBee implementation, all communications must pass through the meter as the gateway/coordinator.



To implement this capability, Sensus plans to provide a factory-build option for the iConA meters to include or exclude a ZigBee RF communications board, providing ZigBee coordinator functionality for the local HAN.



In the FlexNet-only solution, it is assumed that the demand response or Smart Grid device is provided by utility. In the FlexNet to ZigBee solution, it is assumed that the HAN device at the customer premise may be supplied by either the utility or the consumer. In both cases, FlexNet supports a range of customer premise HAN communications for discovery, commissioning and control.

<u>Discovery</u> of a node is simply the identification of a new node within the HAN involving:

- ❑ Announcement – Active and passive device notification methods
- ❑ Response - Includes both endpoints
- ❑ Initial Identification - Device-type and address identification

<u>Commissioning</u> is the network process of adding or removing a node on the HAN with the expectation that the system is self-organizing. This process is decoupled from utility registration. Commissioning involves the following:

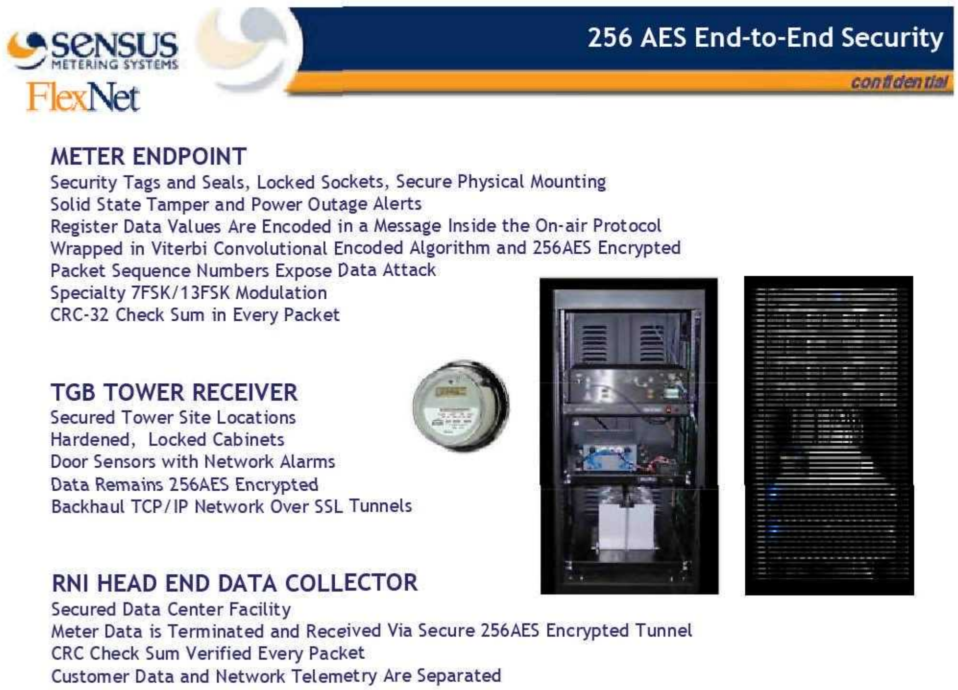
- ❑ Identification - Uniquely identifying the device
- ❑ Authentication - Validation of the device (network key)
- ❑ Configuration - Establishing device parameters (binding)

Control of a node is involves:

- ❑ Organization - Communication paths
- ❑ Optimization - Path selection
- ❑ Prioritization - Communication based on importance

To support the anticipated market growth, FlexNet's demand response and Smart Grid system supports various types of communication. These communication types include regular data transmission of information and health status to the RNI, consumer specific signaling and control signaling, broadcast of load curtailment commands, and receipt of acknowledgements from the endpoints.

256 AES Security is the latest government standard for encryption and protection of data networks and the chosen security method of the FlexNet System. Consumer specific information signaling implies that additional privacy measures and methods are warranted. Control signaling for load control and direct utility communications is a special use of the system and as such, requires robust handling methods. This capability and expectation is based on utility accountability for safe and secure delivery of the control data.



The main security concerns for demand response and Smart Grid are centered on Access Control and Confidentiality, Registration and Authentication.

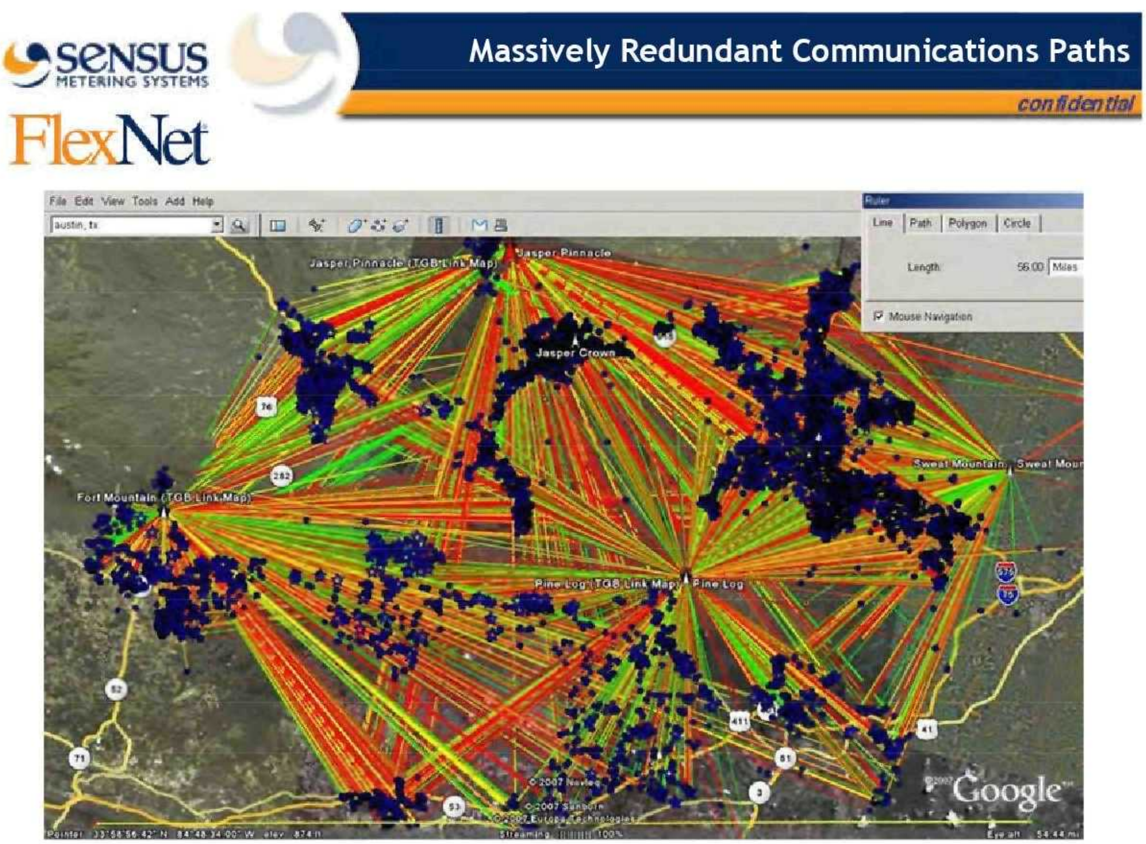
Access Control and Confidentiality address levels of data protection based on data type. All data will have some level of access control but there are various protection methods associated with both data-at-rest and data-in-transit based on data type. The two primary categories are.

- Private Controls - protection methods for confidential or sensitive data (consumer data)
- Utility Controls - protection methods for utility accountable data

Registration and Authentication is crucial since it verifies and validates user participation. Once a node is registered, it is trusted in the network. Therefore registration and authentication involves the following:

- ❑ Initialization – establishes the application/device as a validated node
- ❑ Validation – validates the application's data
- ❑ Correlation – correlating a consumer account with a device, application or program
- ❑ Authorization – rights granted to the applications
- ❑ Revocation – removing an established node, correlation or authorization

Best of Breed Performance and Reliability is a hallmark of the FlexNet system based on primary use licensed band RF communications and massively redundant network design. The successful performance of the FlexNet demand response and Smart Grid applications now and in the future is based on the underlying assumption of reliable RF performance not possible with competing, unlicensed band systems.



The Sensus FlexNet demand response and Smart Grid reliability is based on four major deliverables.

> Availability - The devices and applications are consistently reachable due to superior RF power and range and redundant data paths.
>
> Reliability - The network components are designed and manufactured to be durable and resilient and the network design incorporates TGB network overlap, redundant RNI servers, and buddy mode network repeating.
>
> Maintainability - The FlexNet demand response and Smart Grid applications are designed to be easily diagnosed and managed with comprehensive on-line diagnostics.
>
> Scalability - The system supports a predictable growth in applications and devices through advanced modeling using the Sensus AiR model and extensive RNI scalability. The system also supports unanticipated growth through increasing bandwidth development (13 FSK[3]), the ability to build future capacity into the original deployment, and the flexibility to deploy additional network infrastructure.

Sensus' unique ability to simultaneously broadcast demand response messages to millions of endpoints in only seconds provides FlexNet users with a powerful tool in achieving their demand response goals and side-stepping the costs associated with large spinning reserves.

[3] Frequency Shift Keying

SENSUS METERING SYSTEMS

FlexNet

Fast Demand Response Action & Positive Feedback May Reduce Spinning Backup Generation

confidential

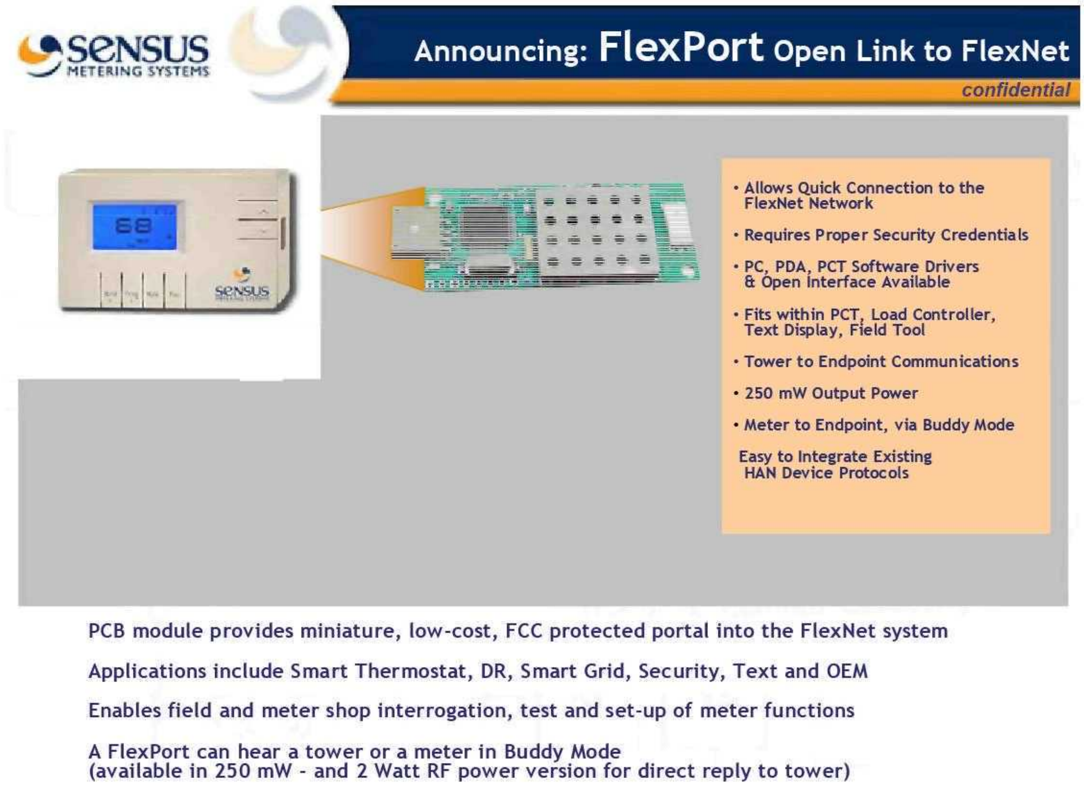
Example for 1,000,000 loads commanded system wide (Assumes 85 TGBs).

STEP 1		***TIME REQUIRED***
- RNI sends broadcast message to TGB's - Load shed command clears NC in RNI, Internet Latency & TGB buffer		2.5 Seconds
STEP 2		
- Each TGB transmits that message on its time slot		1 Second
		3.5 Seconds
- 6 repeats (7x redundancy)		6 Seconds
	TOTAL	9.5 Seconds
STEP 3		
- Acknowledge messages from Meters/ Endpoints: Meter sets command acknowledge bit in standard message Sent at normal transmit interval (4 hr typ)		4 Hours
- Alternative: Fast Acknowledge from 100K endpoints ALOHA hold-off with Group Addressing 100,000 Endpoints/ 150 ms slotting/ 85 TGBs W/ 50% Ovhd		5.9 Minutes

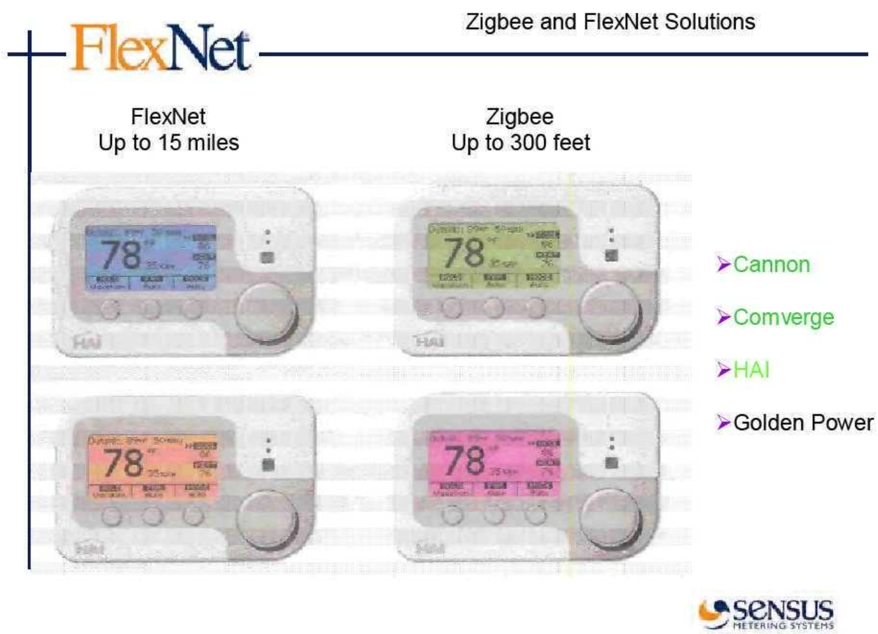
Endpoint devices will fall into two main categories: (1) Utility-supplied FlexNet endpoints developed by Sensus and Sensus partners, and (2) Consumer-supplied ZigBee endpoints supplied by a range of emerging third party companies. Example endpoints are shown in the following table:

Hardware	**Description**	**Function**
iConA Meter	Responsible for measuring electric load at the customer premise and providing gateway, bridging, and general AMI connectivity between the FlexNet AMI network and residential and commercial demand response devices.	Energy measurement and two-way communications and Coordination
PCT	Programmable Communicating Thermostat (PCT)	HVAC Control
Display	In Home Display, especially of consumer HAN status and electric usage and cost (may be bundled with PCT)	Energy Information Display
Load Control Device	Limits connected electric load based on user or utility configuration.	Resource Control
Smart Appliance	A self-aware appliance that communicates and reacts to utility and other control signals based on user configuration	Energy Awareness

Demand Response Endpoints - Sensus is working with a number of third parties to either license the FlexNet technology or market plug-in FlexNet modules and embed the FlexNet radio solution into those endpoints. These include Comverge, Rite-Temp, and HAI for thermostats and Comverge for Load Control devices. To encourage additional partners and utility choices, Sensus is developing a standard plug-in board for easy adoption and configuration by third party endpoint providers.



Most partner/providers anticipate sister product offerings in both FlexNet and ZigBee endpoints to provide choice to future flexibility to utilities. Endpoint offerings are becoming more sophisticated to meet market requirements for color and easy to read user interfaces. Next generation thermostats from multiple vendors will support FlexNet or ZigBee RF connections in the home.



Some regulators and market participants are requesting standalone in-home displays to display frequently transmitted updates regarding usage and critical peak pricing information. Sensus will interoperate with both FlexNet and ZigBee versions of in-home displays.

<u>Smart Grid Endpoints</u> – Sensus is working with utility providers to embed the FlexNet radio into a wide range of Smart Grid devices Capacitor Banks, and Switch Reclosers. Sensus is

also developing a more universal device which can be used to interface with any Smart Grid device with an RS-232, RS-485, or 4-20mAmp interface.

The universal interface is intended to drive additional value and savings in Smart Grid applications at the utility, by providing monitoring and simple control of stranded assets not currently attached to existing SCADA[4] applications.

For additional information on Sensus Demand Response and Smart Grid development, please contact your Sensus regional account representative or:

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Covington, LA
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[4] Supervisory Control and Data Acquisition.

Change Management

I. INTRODUCTION

Implementation of AMI and the technologies enabled by AMI (e.g., DR and Smart Grid) will result in numerous changes in the Companies' business and operations paradigms, business organization and processes, customer strategies, resource planning, energy management policies, engineering practices, service reliability, safety management and regulatory compliance. Consequently, effective management of these organizational changes (i.e., "change management") will play a key role in the Companies' successful AMI implementation. To that end, the Companies plan to initiate a comprehensive Change Management Plan focusing on:

- Assessment of "to-be" process changes and their impacts on the Companies' organizations;
- Development of an overall change management plan;
- Assessment of AMI's impacts on human resources and establishment of a training/redeployment plan to ease the transition for affected employees; and
- Identification of key internal and external stakeholders, formulation of a communication plan and maintenance of communications with the stakeholders in the AMI Project from planning/engineering to post-deployment.

II. PROCESS CHANGES AND ORGANIZATIONS IMPACTED

AMI implementation is expected to cause major job and process changes at the HECO Companies. Anticipated changes are outlined below by affected organization.

A. Customer Service

Call Center: Customer calls are expected to become more complex, involving, for example, AMI meter exchanges, potential rate options and energy efficiency programs, energy usage information, DR device operations, etc.

Billing Inquiries: Customer service representatives will be able to resolve many billing inquiries using on-demand and historical daily/hourly meter reads during the first customer call.

Flexible Move-In/Move-out Service Order Dates: Such flexible dates can potentially be supported including weekends and holidays and by using remote or "virtual" connect and disconnects where available.

Remote Disconnect/Reconnect for Revenue Management: Remote disconnect/reconnect will reduce and may eliminate some customer visits/trips with remote disconnect orders performed in accordance with defined business rules.

Trouble Call: The utilities will be able to ping customer meters to verify single no-light outages.

Proactive Customer Communications: The utilities will be able to leverage timely and accurate AMI data to proactively communicate potential problems to customers, including, for example, outage notification, high-bill alerts, abnormal energy usage alerts, etc.

B. Billing

Final Bill Estimates: AMI will enable more accurate final bill estimates using daily meter read data and on-demand meter reads.

DR Program Support: DR devices will communicate through the AMI network and confirm customer activity, and will enable more complex rates.

Flexible Billing Dates: AMI could support flexible billing dates as meter routes are no longer necessary.

C. Revenue Management

Remote Disconnect/Reconnect: This capability will reduce and may eliminate some customer visits/trips with remote disconnect orders per business rule.

Meter Tampering: The utilities will be able to follow up on the more frequent identification of meter tampering alerts.

Consumption on Inactive Meters: AMI will enable faster detections of move-ins that do not have registered accounts.

Prepaid Accounts: AMI could potentially enable the use of disconnect-reconnect devices to support prepaid accounts.

D. Meter Operations

Meter Shop: Meter sample testing will need to cover communication modules, meter read intervals, and time synchronization, etc. in addition to meter accuracy.

TOU Rates: Hourly or more frequent meter data from AMI can replace TOU meters. This process change will also affect inventory and meter shop testing.

E. New Services

AMI Communication Adequacy: The utilities will need to check the adequacy of AMI communication coverage and signal strength as part of the new meter set process and systematically generate a work order to the AMI network O&M organization if an AMI system upgrade is needed.

F. Rate Design

Rate Design: Stakeholders will benefit from flexible sampling and more accurate and timely data for load research and rate analysis.

DR Program Support: DR devices will communicate through the AMI network and confirm customer activity, enabling more complex tariffs.

G. Distribution Operations

Outage Verification: AMI will be used to ping meters to verify outages before dispatching troubleshooters to the outages.

Automated Outage Notification: AMI outage notification messages (or last gasps) will be processed to improve accuracy of predicted outage analysis.

Analytical Support for Emergency Load Transfers: AMI data can be used to estimate load transfers based on near real-time data.

Service Restoration Confirmation: AMI will be used to confirm restoration of service before callbacks to customers and to systematically confirm restoration to identify nested outages after each restoration step.

Distributed Generation Monitoring: AMI will be used to systematically check for reverse power flows due to DG to improve crew safety during outage restoration.

Reliability Reporting: AMI outage restoration messages and their timestamps will be used to improve the accuracy of outage reporting.

AMI Network Restoration: The AMI communication network may be affected by the same power outage events. Restoration of the AMI network and the power system will need to be coordinated.

H. Distribution Planning & Engineering

Field Load Data Collection: AMI will be used to get up-to-date and historical load data instead of dispatching field services personnel to collect data from selected meter load points.

Electric Distribution Network Modeling: AMI load and voltage data will be used to validate and fine tune the distribution system model used in distribution planning and engineering, and subsequently improve the efficiency and capacity utilization of system assets.

Transformer Load Management: AMI will significantly reduce load estimation errors and will provide more accurate load profiling to better track loading against optimal transformer loading guidelines.

Proactive Problem Solving: AMI will be used to monitor load, voltage, and power quality at select delivery points to identify and resolve potential problems proactively.

III. OVERALL CHANGE MANAGEMENT PLAN

A. Process Owners and Stakeholders

As AMI-enabled processes are designed and gaps analyzed, internal stakeholders (e.g., process owners and business unit managers at the Companies) and external stakeholders (e.g., government, consumers, and labor unions) will be identified.

B. Assessment

Since the AMI Project impacts other business units and operations, it is essential to assess the key stakeholders' needs and identify possible risks to the project. As part of the AMI Project, the Companies will:

- Develop a communications plan to create a better understanding of the AMI technology;
- Identify gaps in knowledge and skill sets of employees to craft/improve the employee training plan; and
- Develop a Change Management Plan.

C. Monitoring Key Performance Indicators

The AMI business case affects several Key Performance Indicators ("KPI") that the Companies routinely monitor and report, including:

- Cost of field operations – Based on the number of field trips for meter and bill investigations, etc.;
- Customer satisfaction index – Assessing customer response time, service reliability, the number of billing inquiries, the number of manual re-bills per month, etc.;

- Total Unaccounted for Energy ("UFE"); and
- Meter Reading Costs.

As part of their change management efforts, the Companies can track improvements in their affected KPIs in order to monitor the anticipated AMI system benefits.

D. <u>Communications Plan</u>

The Companies have already begun to build an awareness of AMI technology through town hall meetings, management briefings, and publications such as the Powerlines commercial customer newsletter and the Currents employee newsletter. See pages 9 and 10 for HECO Powerlines AMI Article and page 11 for HECO Currents Employee Newsletter.

Communication is a critical element in managing stakeholder expectations, identifying barriers as well as potential solutions for acceptance and support of AMI. The primary goal of the communications plan is to keep stakeholders informed and actively involved, and to disseminate timely and appropriate information to the right audience at the right time. The communications plan will be designed utilizing best practices for conducting focused communications with stakeholders, labor unions, governments, employees at large, customers and the general public on a regular periodic and as-needed basis.

In addition to a regular communications schedule, the communications plan will identify project milestones and other major events that would trigger communications, along with the target audiences, appropriate communication media and method for each milestone or event. The target audiences may include for example:

- The Companies' AMI management and project team, which will promote and guide the introduction and acceptance of AMI;
- The Companies' executive and senior management, who approve funding and provide guidance on significant project issues;

- Stakeholders, key internal (e.g., various process owners and business unit managers) and external bodies (e.g., government, consumers and labor unions) who will be affected by the AMI Project implementation;
- Impacted employees whose jobs will change due to the project;
- The Companies' employees in general;
- Labor unions;
- Customers; and
- The Companies' suppliers.

E. Communication Channels and Materials

The communications plan will utilize existing and potentially new communication channels, as appropriate, including for example: the Internet/world wide web, e-mail, paper (fact sheets, posters, bill inserts, etc.), town hall meetings, radio and television, etc. It will leverage a variety of communication materials that have been developed as part of the project engineering efforts and will continually be expanded and refined throughout the implementation of the project. These materials may include:

<u>AMI Initiative Overviews</u>: Overview presentations of the AMI Project objectives, required technologies and related information systems, HECO customer and societal benefits, etc.;

<u>AMI Fact Sheets</u>: An AMI fact sheet on key AMI components such as AMI meters, AMI communication networks, MDMS, and HAN/Energy Efficiency Program support, etc.;

<u>Frequently Asked Questions (FAQ)</u>: A continually updated AMI Frequently Asked Questions publication;

<u>AMI Initiative Brochure</u>: An AMI Initiative Brochure that can be distributed to customers through bill inserts or by field personnel during meter exchanges to answer common customer questions regarding AMI; and

<u>Minute Updates</u>: Brief communiqués routinely distributed to detail the latest project and technology developments for stakeholders and select target audiences.

IV. Employee Transition/Training Plan

Some new positions have already materialized as a result of the Companies' pilot AMI projects and interest in developing and deploying an AMI system.

A. Job reclassifications/skill set definition

The Companies will establish an account of jobs that are impacted, new competencies and skill sets required for changes to existing job positions, as well as potentially new jobs that have yet to be identified. Existing job functions that may require new responsibilities and competencies/skills include, for example:

Call Center customer service representatives – who will need to be able to handle more complex information (e.g., daily updated hourly energy consumptions instead of monthly billing reads), solve more problems directly with customers (e.g., performing an on-demand meter read to resolve a billing inquiry instead of referring it to Billing), and answer more complex questions (e.g., "which DR rate is better for me?");

Meter Technicians – who will need to be able to test and configure communication modules, and verify adequacy in communication coverage and strength, in addition to testing meters in the shop or in the field; and

Trouble Shooters and Line Crews – who will need to be able to recognize possible AMI communication equipment attached to the electric power infrastructure and perform elementary inspections and troubleshooting of the equipment.

New job functions/positions that have yet to be well defined may include, for example:

Field Communications Technicians – to maintain communications to the meters and DR endpoint devices within customers' homes;

Customer Installation Coordinator – to ensure installation of the appropriate AMI communication equipment and endpoint devices, and coordinate with electricians that install smart thermostats and air conditioners/water heaters to ensure continued success of energy efficiency programs; and

AMI Data Manager – to ensure that the necessary AMI data is captured and processed to support the needs of other business functions such as Load Research, Dynamic Pricing/Demand Response and Distribution Operations to ensure that the enterprise benefits of AMI are achieved.

B. **Workforce Transition**

The Companies will strive to minimize negative impacts of AMI on its workforce through training, natural attrition, reduced overtime, use of temporary employees and redeployment of impacted employees. The AMI team is working with the Companies' Customer Service, Human Resources and Industrial Relations departments to develop a workforce transition plan to manage the transition of employees whose jobs are impacted by AMI.

C. **Training Plan**

The AMI Training Plan will organize the activities and efforts associated with training impacted employees in order to help them to:

- Apply AMI technology and meter data management functions, and adopt and embrace the new AMI-enabled work processes;
- Transition to the new job functions listed above; and
- Transition to other jobs with other companies.

The Training Plan will involve identification of target audiences, applicable technologies and work processes; individual counseling sessions; timing (schedule and event triggers) of training courses/sessions; and training materials and resource requirements, etc.

HECO *Powerlines* e-Newsletter – AMI Article Excerpt

SMART METER
Project Expands to Ocean Pointe

After a successful technical trial in 2006 involving 500 smart meters on Oahu, Hawaiian Electric Company, Inc. (HECO) expanded the wireless smart meter project to 3000 meters in the Ocean Pointe and Ewa Beach communities this March. Smart meters have been dispersed throughout Oahu to provide a realistic network environment to further explore the operational performance and capabilities of an advanced metering network.

HECO's Customer Installations Department (CID) is currently working with global metering leader, Sensus Metering Systems Inc., to deploy, validate, and gain operational insight into an advanced metering and communications technology called FlexNet. This unique technology provides capabilities such as automated meter reading, interval data collection, voltage monitoring, on-demand meter reads, and remote control of customer loads. All of these features support new pricing and demand response initiatives that will help our customers manage their electricity use in new ways.

"One of the outcomes we expect from using the Sensus FlexNet system is having a variety of pricing options to offer customers that will enhance energy conservation efforts. We also expect to gain additional customer benefits from the automated notification and load control capabilities of the system," said Dr. Karl Stahlkopf, HECO Senior Vice President of Energy Solutions and Chief Technology Officer.

HECO's meter personnel perform a test on the FlexNet meter

FlexNet is an advanced, two-way communications network that uses existing paging towers to communicate with meters and other smart devices. In Hawai'i, there are approximately 70 existing tower sites on all islands available to build out the FlexNet communications network. Based on successful results of our technical trial,

continued

SMART METER

Smart Meter continued

HECO believes that full scale meter deployment on Oahu may require less than a dozen of these tower sites. A unique feature of the FlexNet technology is the ability to use "buddy" meters to improve network coverage and optimize the number of towers required.

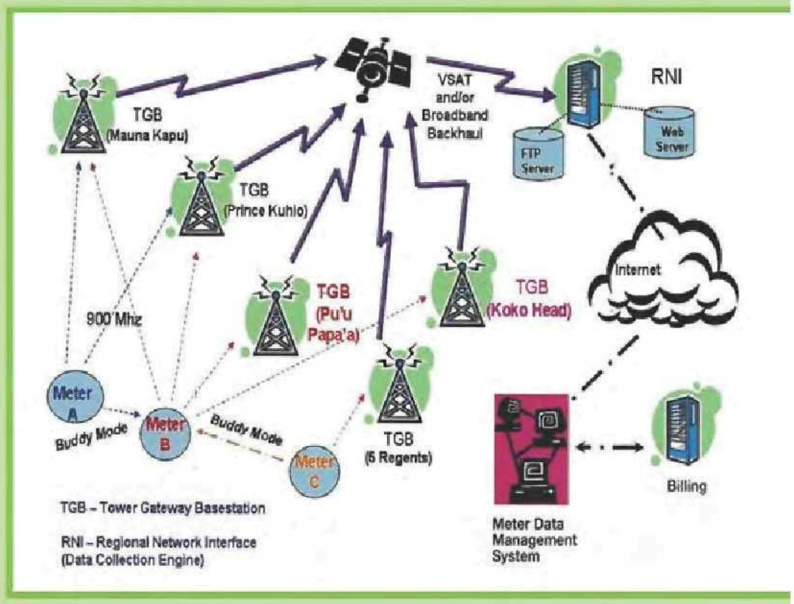
At the present time, five towers located in Makakilo, Waikiki, Salt Lake, Koko Head, and Kaneohe, form the basis of HECO's pilot FlexNet communications network.

After being acquired at the tower sites, meter data is sent electronically to a remote data storage "warehouse" which serves as an off-site backup facility. Encrypted data is transmitted over the Internet from the off-site backup facility to HECO's Billing system.

FlexNet allows electric utilities to perform interval (i.e. 15-minute or hourly) and on-demand reads. Interval reads enable HECO to offer time varying rates so that customers who use less electricity at critical peak demand times can reduce their electric bill. This capability also enables HECO to capture consumption data that can be used to improve utility system planning and system operations. On-demand reads simply mean that our customer service representative can read meters and power status in near real-time and provide quicker customer response. In fact, this can happen while our representative is talking on the phone with a customer.

Beyond reading meters, FlexNet communications can provide load control capabilities in the event of a utility system emergency. For example, HECO could initiate over-the-air commands to temporarily shut off electric loads and raise air-conditioning thermostat settings to help reduce electricity demand and avert emergency situations. The on-demand communications feature will also enable HECO to start and stop electric service as well as alert HECO about meter tampering. And, the ability to communicate with smart meters will help to speed the restoration of power after an outage.

HECO has made significant progress over the past several years in exploring and validating advanced metering and communications. Advanced Metering Infrastructure (AMI) technology continues to improve every day and many utilities throughout the country are moving from the pilot phase into full-scale AMI deployments. HECO's pilot AMI project efforts will run into 2008, and if successful, HECO will consider commercial deployment of the smart meters to more customers.



HECO Currents Employee Newsletter – AMI Excerpt

Currents is published for employees of HECO, MECO & HELCO and retired friends

Currents

April/May 2007 Volume 17, Number 3

Smart meters advance on Oahu

What is a smart meter? It may not have an advanced degree in physics, but a smart meter can make a world of difference to help Hawaiian Electric Company employees across almost every department perform their jobs more effectively and efficiently.

What if you could tell customers exactly how much electricity they are using at a given moment and exactly how much their utility bill will be? Or, you could tell when someone is tampering with their meter? Or, in the event of a system emergency, you could shut off electric water heaters and raise air-conditioning thermostat settings to help temporarily reduce electricity demand? What if you could do all of this remotely? These are just *some* of the things a smart meter can do.

Honeywell International employee Jim Conrad install a Sensus FlexNet meter in an Ocean Pointe neighborhood.

Since 2006, HECO's **Customer Installations Department** has been working with global metering leader Sensus Metering Systems Inc. to install the FlexNet™ advanced metering technology in select homes and businesses on Oahu. After a successful technical trial last year involving 500 smart meters proved that wireless technology holds promise for advanced metering, HECO expanded the smart meter project in March 2007 to 3,000 homes in the Ocean Pointe community and surrounding areas in Ewa Beach.

Since the FlexNet two-way communication network relies on existing paging and cellular radio towers to communicate with meters, there were essentially no infrastructure changes needed or permits required that would hamper the deployment of the project and timeline. Even more critical, the network coverage reached far beyond expectations, demonstrating that Oahu's dense urban environment, mountains and deep valleys, and heavy radio frequency environment do not hinder the performance of the FlexNet system.

The FlexNet meter looks no different from a regular residential meter, but where a regular meter simply monitors electricity usage, the FlexNet meter can provide such features as reliable hourly and on-demand reads that enable offering time-varying rates so customers who use less electricity at critical peak demand times can get a break on their electric bill.

"A distinct advantage of a two-way communication system is being able to offer more options and enhanced services to our customers while also providing more accurate billing," said **Darren Yamamoto**, manager of Customer Service.

Another key component of the FlexNet system is the potential for integration with other "S" projects within

continued on page 3

Smart meters

continued from page 1

Hawaiian Electric, namely the Customer Information System, Outage Managament System, and Emergency Management System projects. Remote load-control capabilities, service connects and disconnects, as well as meter tampering alerts are all features of the system. In addition, the FlexNet system's ability to create immediate alert reports means that in the future, these smart meters can provide automated outage notification to HECO, assisting our Call Center representatives in tracking the status of our outage restoration process. The system will pinpoint the customers affected by the outage and the fault location and restoration process, which will improve operations reliability and efficiency.

Deploying the meters in the Ocean Pointe community drew upon the resources of **Customer Service, Energy Services, Regulatory, Legal, Corporate Communications, Community Relations, Safety/Security and System Operations** as the process evolved. The expanded pilot project runs through 2008, and if successful, HECO will consider full-scale commercial deployment of the smart meters to more customers.

	AMI Benefits
Benefit Area	**AMI Benefits**
Meter Reading	– Eliminate manual on and off-cycle meter reading
Customer Field Operations	– Reduce field trips for meter test and meter investigations, etc. – Eliminate field trips for move-in/move-out, disconnect and reconnect of services
Customer Service & Call Center	– Improve customer response – Reduce billing inquiry call volumes & resolution times – Reduce trouble call volume – Increase one-call resolutions
Billing	– Improve billing accuracy – Reduce number of billing inquiries – Improve response to billing inquiries – Reduce manual billing, bill estimation, and re-bills
Revenue Management	– Faster detection of meter tampering and energy diversions – Faster detection of meter problems such as stuck meters – Faster detection of consumption on vacant premises – Eliminate field trips for disconnect and reconnect of services
Distribution Operation & Outage Management	– Improve customer trouble response – Reduce outage duration – Verify service restorations – Improve outage and reliability reporting accuracy
Enabling of Energy Efficiency Programs	– Support Load Research with higher data resolution and flexible sampling – Enable demand response programs – Enable time of use, critical peak, and other dynamic pricing structures – Improve billing accuracy for small DG and cogeneration
Facilitation of Customer Energy Management	– Enable customer to manage electric power usages – Enable customer to limit electric power consumption and energy bill
Distribution Planning & Engineering	– Improve distribution feeder and transformer capacity utilization – Improve delivery voltage and power quality – Reduce distribution system losses – Enable proactive problem resolution
Future Enabling of Customer Service Enhancements	– Proactive customer communications of outages and high-bill alerts – Future enabling of flexible move-in/move-out dates – Future enabling of billing dates

Rev: April 30, 2007

Accuracy Tests
Electro-Mechanical and Sensus AMI Meters

This document is comprised of the following:

(1) Report dated April 30, 2007 documenting the testing of electro-mechanical and Sensus iCon (AMI) meters

(2) Report dated November 10, 2008 documenting the testing of the new Sensus iConA (AMI) meters

Rev: April 30, 2007

Accuracy Tests of Electro-Mechanical and Sensus iCon (AMI) Meters

(April 30, 2007)

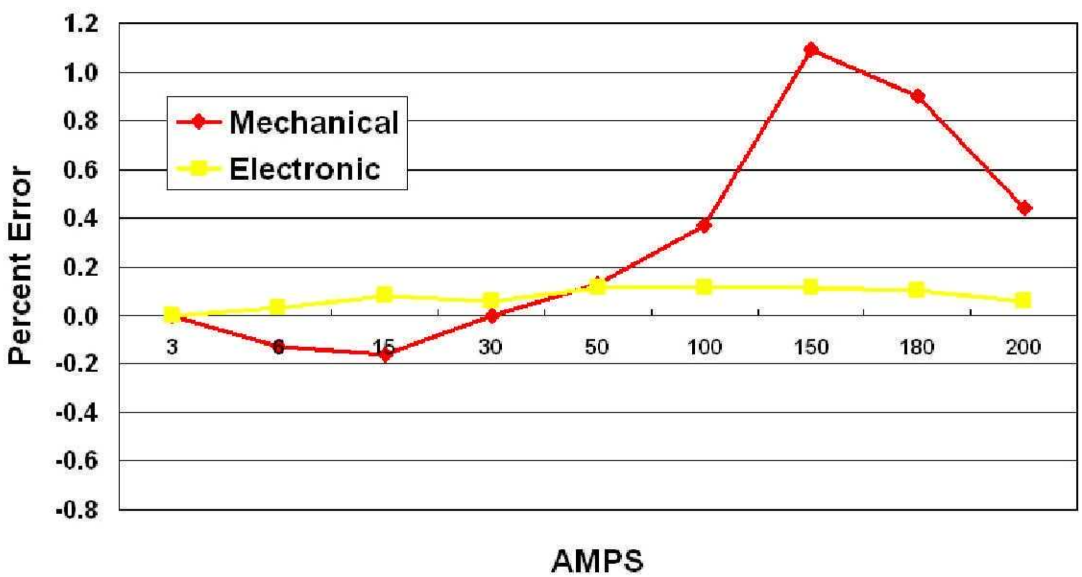
Summary

A representative sample of approximately 500 residential electro-mechanical (EM) meters between Pearl Harbor and Diamond Head were replaced by Sensus solid-state meters. The accuracy of the EM meter was compared with that of the solid-state meters across the range of amperages of residential energy use. The EM meters were found to record, on average, 0.4% below the actual test load. The solid-state meters were found to record 0.01% above the actual test load.

Motivation for the Study

Data provided by Alabama Power indicated that, as shown in Figure 1 and Figure 2, both new and in-service electro-mechanical meters are inaccurate between the ANSI test points of 3 amps and 30 amps.

Figure 1
Accuracy of New Mechanical and Electronic Meters, by Amperage



(Source: Derl Rhodes, Alabama Power, *AMR and the Effects on Distribution Assets*; emailed PowerPoint presentation)

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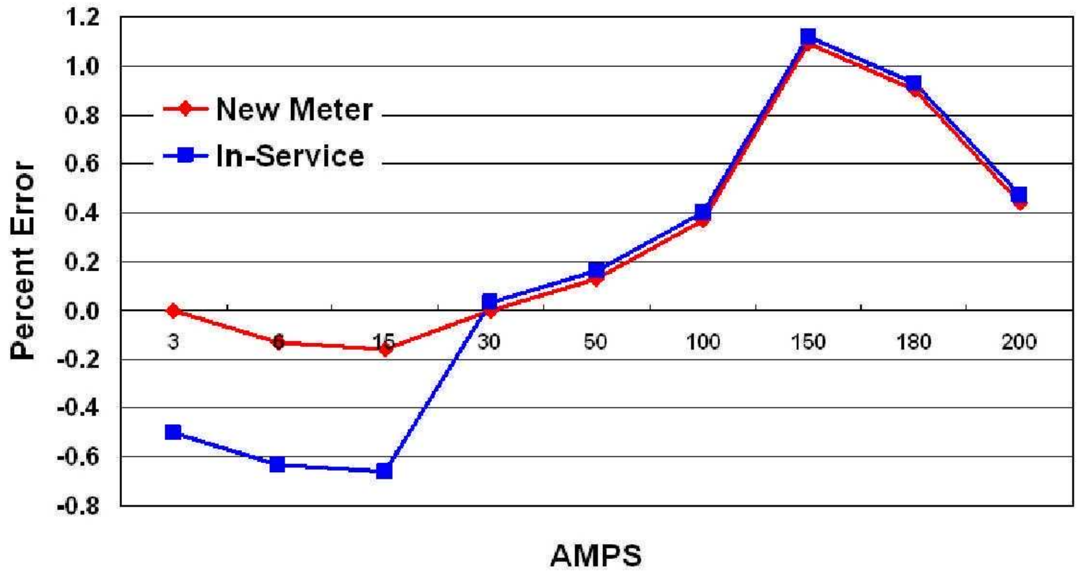
Figure 2
Accuracv of New and In-Service Electro-Mechanical Meters



(Source: Ibid.*)*

Accordingly, in-service electro-mechanical and replacement electronic meters were tested at several points between 2 amps and 30 amps, to verify the findings from Alabama Power.

Sample of Residential Meters

An initial testing of 22 EM meters from the field confirmed that these meters were most accurate at the ANSI test point of 2 amps and progressively less accurate at higher amperages.

Table 1
Accuracy of 22 HECO In-Service Electro-Mechanical Meters

Amperage	Average Percent Error	Standard Deviation
2	-0.134	0.776
3	-0.250	0.516
4	-0.384	0.366
6	-0.385	0.419
8	-0.406	0.387
10	-0.432	0.388
12	-0.531	0.374
20	-0.478	0.350
30	-0.784	0.340

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The size of the standard deviation of the errors indicated that testing 500 meters should be sufficient to declare as statistically significant a difference of 0.5% between the EM and solid-state meters. A difference of 0.5% was chosen as the minimum acceptable precision at the 95% level of confidence.

The first step in drawing the sample of residential meters was to determine the distribution of residential meter models in service on all of O‘ahu and compare it with the distribution of residential meters in service in the area from Pearl Harbor to Diamond Head, the Advanced Meter Infrastructure (AMI) pilot evaluation area.

Compared with all residential meters installed on O‘ahu, the AMI pilot area has proportionately fewer Schlumberger meters and more Sangamo, GE and Westinghouse meters. Accordingly the sample was divided by meter manufacturer and model into 21 strata; these strata accounted for 95% of all residential meters installed on O‘ahu.

Table 2
Sample Strata

Residential Meter		**Population**	**Sample**
Manufacturer	Model	N	n
Westinghouse	D4S	37,749	71
Schlumberger	J5S	32,070	60
General Electric	I70S2	27,698	52
General Electric	I70S	26,294	49
Sangamo	J4S	21,228	40
Sangamo	J5S	17,161	32
Sangamo	J3S	13,883	26
Sangamo	S12S	8,114	15
General Electric	V612S	7,984	15
Westinghouse	D5S	7,854	15
General Electric	I60S	7,430	14
Asea Brown Boveri	AB1ROMR	6,901	13
Westinghouse	D3S	6,036	11
Asea Brown Boveri	ISO1	4,755	11
Westinghouse	D4S5U	4,468	11
Schlumberger	C1S	4,247	11
Westinghouse	D2S5U	4,078	11
Westinghouse	D2S	3,671	11
Asea Brown Boveri	ABS5UR	3,617	11
Landis & Gyr	MSII	3,586	11
Westinghouse	DS	3,065	10

The EM meters tested were about two years older than the average for all residential meters in service on O'ahu. There were no consistent correlations between age of meter and test result. Older meters tested lower at 8, 10, 12 and 30 amps, but higher at 1, 1.5 and 2 amps. The impacts of a two-year difference in age were negligible, however.*

The Test Data

The test data consisted of 483 Electro-mechanical (EM) residential meters formerly installed from Pearl Harbor to Diamond Head and 322 Sensus solid-state meters replacing the EM meters. Meters were tested at thirteen amperages: 0.5, 1.0, 1.5, 2.0, 2.5, 3, 4, 6, 8, 10, 12, 20, 30; not all meters were tested at all points.

As testing progressed it became clear that the variance in the Sensus meter tests was not as large as had been anticipated, and therefore fewer Sensus test results would be needed to achieve the required precision of ±0.5%. Accordingly, not all the replacement Sensus meters were tested; instead, resources were shifted to testing at low loads (<2 amps).

Data Analysis

The test results were first examined for obvious data entry errors; six [0.1%] were found and corrected among the EM test results. None were found among the Sensus meter test results.

Because the observed range of EM meter errors is quite small and extreme values would unduly influence the estimate of the average error, readings that were clearly outliers were identified and set aside. At each test amperage, all the results for EM meters were sorted from largest to smallest. The rule for declaring a test result an "outlier" was an incremental difference of more than 1.0% in a sorted dataset.

* An age difference of two years corresponded to a test result 0.010% lower at 8, 10 and 12 amps; 0.006% lower at 30 amps; 0.065% higher at 1 amp; 0.042% higher at 1.5 amps; and, 0.027% higher at 2 amps. Weighted by the load duration at each amperage, the net effect of being two years older was +0.031%

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For example, the highest results for the EM tests at 4 amps were

…,100.9, 100.9, 100.9, 101.0, 101.0, 101.2, *102.7 104.9, 105.2, 105.9, 148.7*

The break between 101.2 and 102.7 was identified as the point where the outliers began. This process was repeated for each test point.

Initially, 88 EM test results from 27 meters were identified as outliers.* After review of the draft results, a retest for these 27 meters was ordered, but only 19 could be located. Upon retesting, 72 EM outliers [1.4%] remained.

No outliers were found among the Sensus meter test results.

The test readings were averaged by amperage, and weighted by the amperage's relative frequency across the residential load.
The relative frequency that residential customers' loads are at each test amperage was estimated from the hourly data obtained from the 70 residential customers in the 2003 HECO Class Load Study.

Table 3
Relative Frequency of HECO Residential Account Demand in 2003

Amperage	Demand (kW)	Relative Frequency
0.5	0.12	8.9%
1.0	0.24	13.9%
1.5	0.36	14.0%
2.0	0.48	9.4%
2.5	0.60	7.9%
3.0	0.72	9.3%
4.0	0.96	11.4%
6.0	1.44	8.9%
8.0	1.92	5.5%
10.0	2.40	3.5%
12.0	2.88	4.6%
20.0	4.80	2.4%
30.0	7.20	0.5%
TOTAL		**100.0%**

* Five of the 483 EM meters (~1%) had all of their tests set aside; these five accounted for half of the 88 outliers. They averaged 38 years old, compared to 25 years old for all installed residential meters.

Table 4a
All Electro-Mechanical and Sensus Error Test Results,
by Relative Frequency of the Amperage Load in the Residential Population

Amperage	EM Average	EM n	Sensus Average	Sensus n	EM-Sensus delta	Relative Frequency of the Amperage	Std Error of delta	p(delta)	% Signif lower
0.5	98.47	175	100.02	179	-1.55	8.9%	0.122	0.000	8.9%
1.0	99.02	176	100.02	179	-1.00	13.9%	0.201	0.000	13.9%
1.5	99.09	176	100.02	179	-0.92	14.0%	0.042	0.000	14.0%
2.0	100.69	481	100.01	446	0.69	9.4%	0.010	1.000	
2.5	99.51	176	100.02	179	-0.51	7.9%	0.073	0.000	7.9%
3.0	100.38	481	99.99	442	0.38	9.3%	0.035	1.000	
4.0	99.58	483	99.99	442	-0.42	11.4%	0.008	0.000	11.4%
6.0	99.77	483	99.99	442	-0.23	8.9%	0.014	0.000	8.9%
8.0	99.60	483	100.00	442	-0.40	5.5%	0.012	0.000	5.5%
10.0	99.64	483	100.00	442	-0.36	3.5%	0.006	0.000	3.5%
12.0	99.66	482	100.00	442	-0.34	4.6%	0.004	0.000	4.6%
20.0	99.81	479	100.00	334	-0.20	2.4%	0.003	0.000	2.4%
30.0	99.94	482	100.01	442	-0.07	0.5%	0.003	0.000	0.5%
Frequency-weighted average =	**99.54**	345	**100.01**	322	**-0.47**	100.0%	0.059	0.000	81.3%

Table 4b
Electro-Mechanical and Sensus Error Test Results *omitting Outliers*, by Relative Frequency of the Amperage Load in the Residential Population

Amperage	*EM Average*	*EM n*	Sensus Average	Sensus n	delta	Relative Frequency of the Amperage	Std Error of delta	p(delta)	% Signif lower
0.5	*98.94*	*172*	100.02	179	-1.08	8.9%	0.043	0.000	8.9%
1.0	*99.39*	*173*	100.02	179	-0.63	13.9%	0.036	0.000	13.9%
1.5	*99.53*	*174*	100.02	179	-0.49	14.0%	0.042	0.000	14.0%
2.0	*99.64*	*472*	100.01	446	-0.37	9.4%	0.010	0.000	9.4%
2.5	*99.65*	*173*	100.02	179	-0.38	7.9%	0.072	0.000	7.9%
3.0	*99.70*	*474*	99.99	442	-0.30	9.3%	0.035	0.000	9.3%
4.0	*99.74*	*474*	99.99	442	-0.25	11.4%	0.009	0.000	11.4%
6.0	*99.78*	*475*	99.99	442	-0.22	8.9%	0.011	0.000	8.9%
8.0	*99.79*	*477*	100.00	442	-0.21	5.5%	0.005	0.000	5.5%
10.0	*99.81*	*477*	100.00	442	-0.19	3.5%	0.004	0.000	3.5%
12.0	*99.82*	*476*	100.00	442	-0.18	4.6%	0.004	0.000	4.6%
20.0	*99.92*	*474*	100.00	334	-0.08	2.4%	0.003	0.000	2.4%
30.0	*100.02*	*477*	100.01	442	0.01	0.5%	0.002	1.000	
Frequency-weighted average =	***99.59***	*340*	**100.01**	322	***-0.42***	100.0%	0.006	0.000	99.5%

Weighted Test Results

The results are summarized in Tables 4a and 4b, above. Table 4a contains all the tests; Table 4b omits the 72 EM test outliers.

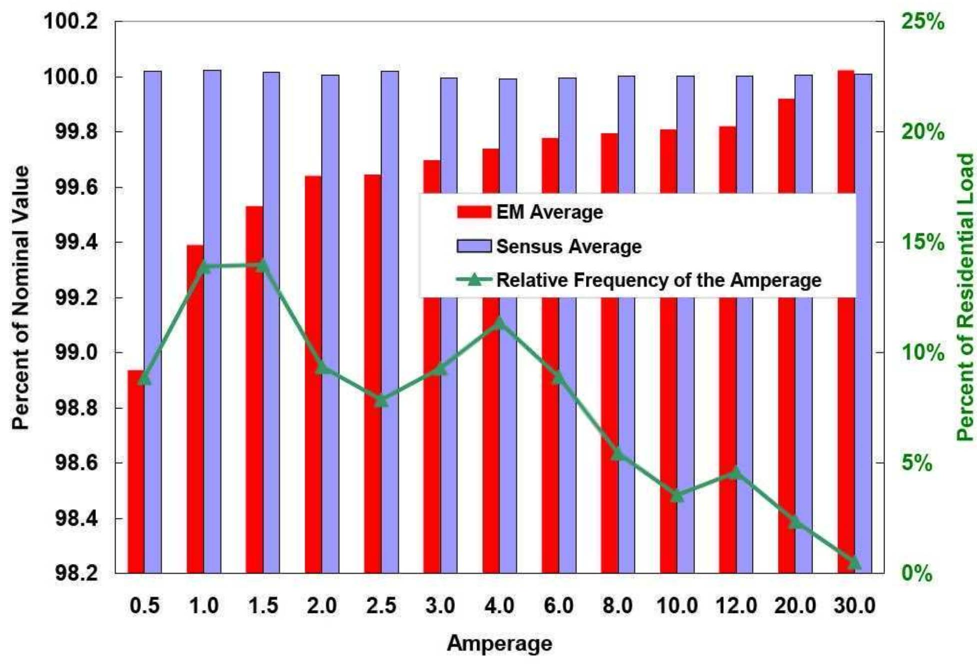
A total of 5,040 EM tests averaged 99.54% of the nominal test load. A total of 4,590 Sensus tests averaged 100.01% of the nominal test load. The EM meters tested significantly lower than the Sensus meters at all loads except 2.0 amps and 3.0 amps.

When outliers were omitted, a total of 4,968 EM tests averaged 99.59% of the nominal test load. Minus outliers, the EM meters tested significantly lower than the Sensus meters at all loads except 30.0 amps. The greatest discrepancies occurred at the most frequent loads.

Distribution of the Test Results

Figure 3 shows the distribution of the EM and Sensus test results, and the relative frequency among residential loads of each test amperage.

Figure 3
Average Accuracy of In-Service Electro-Mechanical Meters and Replacement Sensus Meters



Conclusion

The differences between the EM and Sensus test results are statistically significant. The EM meters averaged 0.41% lower than the actual test loads; the Sensus meters averaged 0.01% higher. The results can be reliably considered to apply to all residential meters installed on O‘ahu.

Rev: Nov 10, 2008

Accuracy Tests of Sensus iConA (AMI) Meters

(November 10, 2008)

Summary

The newest generation Sensus single phase meter is the iConA. HECO performed 13-point hypersequence accuracy testing on 90 of the first 1,440 meters received. This is the same test performed in the "Accuracy Test of Electro-Mechanical and Solid-State Meters" document. The April 30, 2007 result of this document are compared to the iConA in the body of this document.

Motivation for the Study

"Accuracy Test of Electro-Mechanical and Solid-State Meters" documents the statistical different between electro-mechanical and the first generation Sensus iCon meter. The iConA meters were tested determine if the accuracy of the* iConA is significantly different from the iCon meters.

Sample of iConA Meters

HECO purchased and received 1,440 (15 pallets) iConA meters in the month of September 2008. Initially, four boxes (16 meters) were randomly selected from the first two pallets (96 meters). After reviewing the results it was determined that there were no significant issues. A minimum of one box was tested from each of the remaining pallets. In all 90 meters were hypersequence tested, or 6.25% or the 1,440 meter shipment. All 1,440 meters were tested at light load, full load, and 0.5 power factor.

All meters in this test were form 2S class 200 iConA meters, manufactured in the month of August 2008.

The Test Data

Meters were tested by HECO at thirteen amperages: 0.5, 1.0, 1.5, 2.0, 2.5, 3, 4, 6, 8, 10, 12, 20, 30. These were the same amperage load as tested in the "Accuracy Test of Electro-Mechanical and Solid-State Meters" document.

During the test, two meters were found to have results out of 0.4% accuracy. Both of these meters registered 97.7% accuracy at one of the 13 amperage tests. Both meters were subsequently retested several times and this level of discrepancy was not reproduced. After consultation with Sensus it was deemed that these errors were attributed to short settling times on HECO's meter test board. Southern Company has also witnessed similar issues.

These two erroneous test results were discarded. Both meters were retested several times. Variances between the repeated tests were less than 0.05% at any amperage except 0.5A. The variance at 0.5A was 0.06% and 0.10% for the two meters, supporting the fact of variance due to the short settling time. The repeated test results for each of these two meters were averaged and reflected in the data analysis.

The settling time has been adjusted on the HECO test boards subsequent to the findings of this test.

Data Analysis

There were no "outliers" in the data, as described in the previous test report. The maximum deviation at any amperage was 0.68% at the 0.5A. This, however, could be attributed to the settling time issue. All other test amperages varied no more than 0.38%

The meter accuracy of all 90 meters were averaged for each of the 13 amperage loads and subsequently used for iConA meter comparison.

The average of all meters at any amperage was no less than 0.01%. and more than 0.03% below the actual test load.

Individual accuracy measured at all amperages was no less than 99.62% and no more than 100.30%. This was again at the first test load of 0.5A. The remaining data varied no more than 0.38% at any amperage.

Figure 1
iConA Test Results: Average, Minimum, and Maximum Results

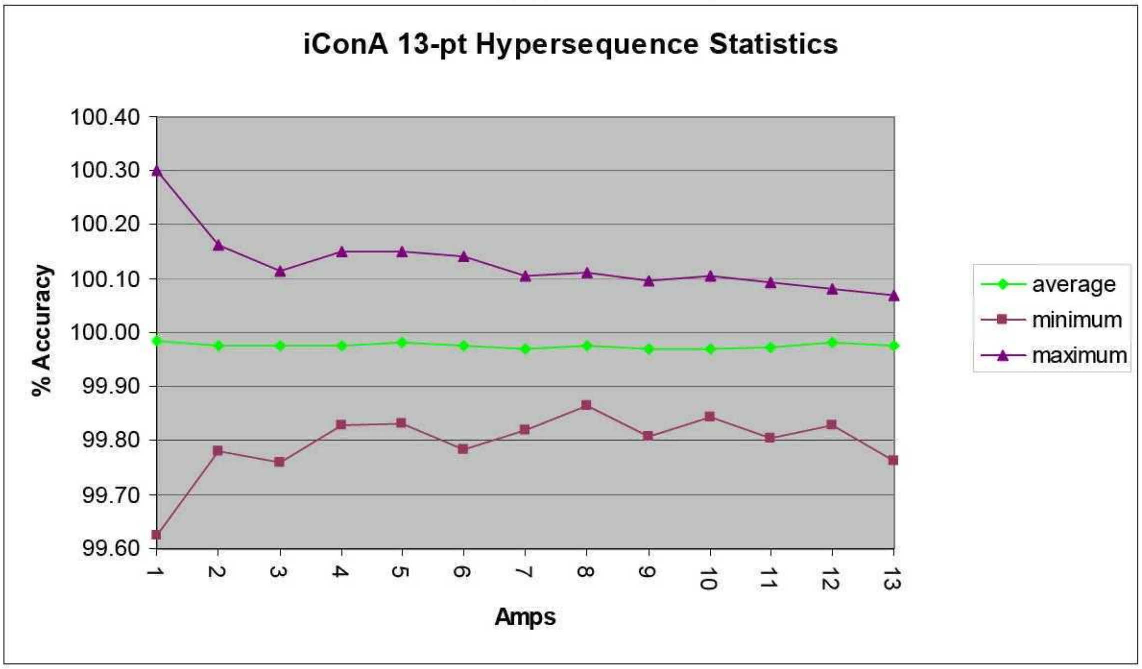


Table 1
All Electro-Mechanical and Sensus Error Test Results, by Relative Frequency of the Amperage Load in the Residential Population

Amperage	iConA avg	iConA min	iConA max	iConA std dev	delta error	rel freq of amps	EM avg (ref)	iCon avg (ref)
0.50	99.99	99.62	100.30	0.1265	-1.05	8.87%	98.94	100.02
1.00	99.98	99.78	100.16	0.0826	-0.59	13.90%	99.39	100.02
1.50	99.97	99.76	100.12	0.0741	-0.44	13.98%	99.53	100.02
2.00	99.97	99.83	100.15	0.0631	-0.33	9.36%	99.64	100.01
2.50	99.98	99.83	100.15	0.0608	-0.33	7.87%	99.65	100.02
3.00	99.98	99.78	100.14	0.0656	-0.28	9.29%	99.70	99.99
4.00	99.97	99.82	100.10	0.0600	-0.23	11.37%	99.74	99.99
5.00	99.97	99.86	100.11	0.0573	-0.20	8.90%	99.78	99.99
6.00	99.97	99.81	100.10	0.0620	-0.19	5.45%	99.79	100.00
10.00	99.97	99.84	100.11	0.0556	-0.17	3.55%	99.81	100.00
12.00	99.97	99.80	100.09	0.0568	-0.16	4.58%	99.82	100.00
20.00	99.98	99.83	100.08	0.0521	-0.06	2.37%	99.92	100.00
30.00	99.98	99.76	100.07	0.0557	0.05	0.51%	100.02	100.01
weighted avg	**99.98**				**-0.39**	100.00%	**99.59**	**100.01**

Weighted Test Results

The resulting weighted average delta between EM and the iConA was -0.39, compared to the iCon at -0.41.

As with the iCon meters the greatest discrepancies between the iConA and EM occurred at loads of 4A and below, accounting for 75% of the most frequent loads.

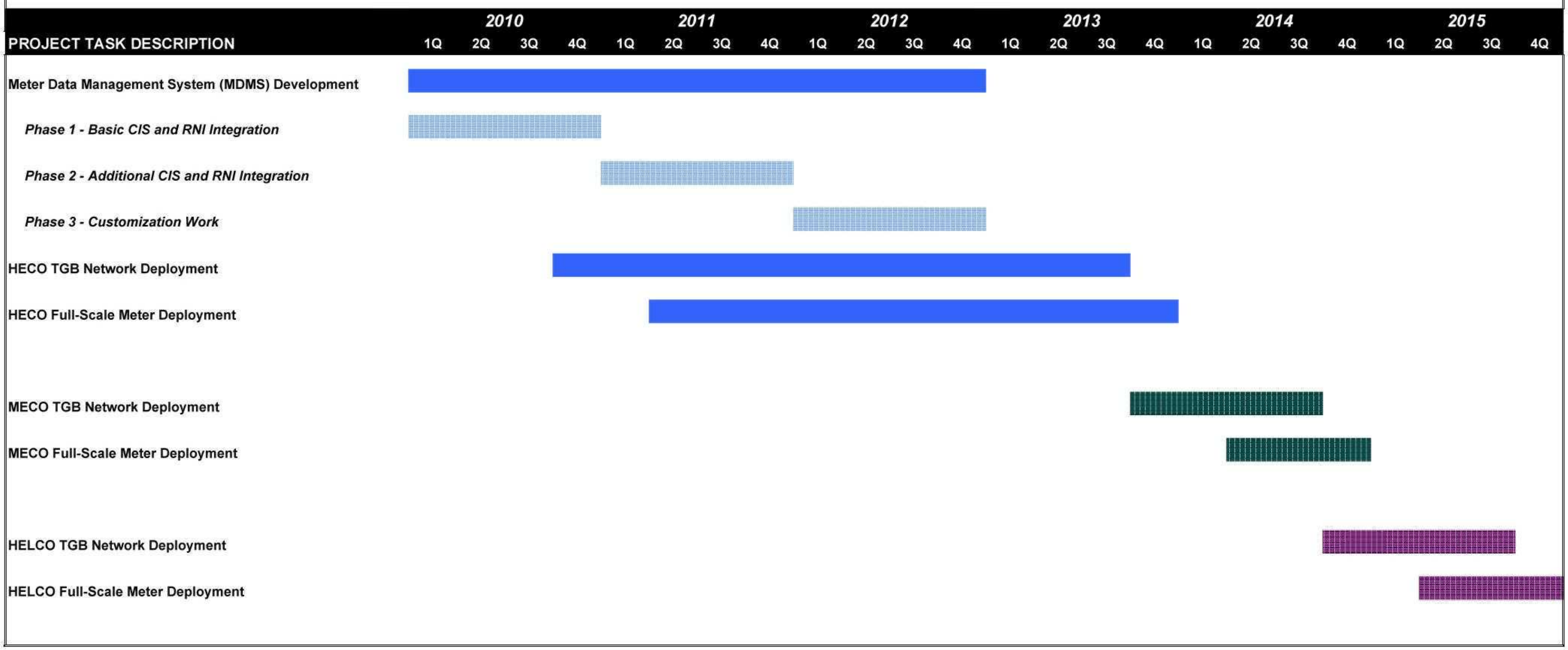
Conclusion

The differences between the iConA and iCon test results are insignificant compared to the differences between the EM and iCon test result. The EM meter averaged 0.41% lower than the actual test loads and the iConA meter averaged 0.02% below.

ENERGY THEFT ESTIMATES

	Estimated Revenue Lost from Energy Theft	% of Losses Recoverable with AMI			% of Revenues Recoverable with AMI
		Min	Max	Midpoint	
EPRI Study	1.0%	20%	30%	25%	0.25%
SDG&E	0.30%	NA	NA	8.5%	0.03%
SCE	0.25%	NA	NA	25%	0.06%
Duke Power	0.50%	NA	NA	25%	0.13%
Dominion	NA	NA	NA	NA	0.10%
Low Estimate					0.03%
High Estimate					0.25%
Average					0.11%
Midpoint					0.14%

EXHIBIT 18
OVERALL PROJECT SCHEDULE



PROJECT COSTS AND QUANTIFIABLE BENEFITS

The following tables provide breakdown of costs and quantifiable benefits of the AMI Project as discussed in Section X.

Table 1 - AMI Implementation Costs (in $000s)

IMPLEMENTATION COSTS (in $000s)		2010	2011	2012	2013	2014	2015	TOTAL
HECO	Proj Mgmt	855	881	909	928	-	-	**3,573**
	Meters	-	14,979	15,236	15,502	-	-	**45,717**
	MDMS	5,424	4,247	1,208	153	-	-	**11,032**
	Network	54	84	67	67	16	16	**304**
	Total	**6,333**	**20,191**	**17,420**	**16,650**	**16**	**16**	**60,626**
MECO	Proj Mgmt	292	301	345	600	811	-	**2,349**
	Meters	-	-	-	-	11,736	-	**11,736**
	MDMS	1,201	940	268	34	-	-	**2,443**
	Network	12	3	3	3	71	-	**92**
	Total	**1,505**	**1,244**	**616**	**637**	**12,618**	-	**16,620**
HELCO	Proj Mgmt	292	288	320	279	535	549	**2,263**
	Meters	-	-	-	-	-	15,411	**15,411**
	MDMS	1,417	1,110	316	40	-	-	**2,883**
	Network	14	4	4	4	4	105	**135**
	Total	**1,723**	**1,402**	**640**	**323**	**539**	**16,065**	**20,692**
TOTAL	Proj Mgmt	1,439	1,470	1,574	1,807	1,346	549	**8,185**
	Meters	-	14,979	15,236	15,502	11,736	15,411	**72,864**
	MDMS	8,042	6,297	1,792	227	-	-	**16,358**
	Network	80	91	74	74	91	121	**531**
	Total	**9,561**	**22,837**	**18,676**	**17,610**	**13,173**	**16,081**	**97,938**

Table 2 - AMI Operating Costs (in $000s)

OPERATING COSTS (in $000s)		2010	2011	2012	2013	2014	2015	TOTAL
HECO	Proj Mgmt	-	-	-	-	934	954	**1,888**
	Meters	-	15	95	226	660	718	**1,714**
	MDMS	244	400	407	380	388	746	**2,565**
	Network	-	266	549	852	885	918	**3,470**
	Total	**244**	**681**	**1,051**	**1,458**	**2,867**	**3,336**	**9,637**
MECO	Proj Mgmt	-	-	-	-	-	538	**538**
	Meters	-	-	-	-	25	262	**287**
	MDMS	54	89	90	84	86	165	**568**
	Network	-	-	-	-	198	210	**408**
	Total	**54**	**89**	**90**	**84**	**309**	**1,175**	**1,801**
HELCO	Proj Mgmt	-	-	-	-	-	-	-
	Meters	-	-	-	-	-	35	**35**
	MDMS	64	104	106	99	101	195	**669**
	Network	-	-	-	-	-	284	**284**
	Total	**64**	**104**	**106**	**99**	**101**	**514**	**988**
TOTAL	Proj Mgmt	-	-	-	-	934	1,492	**2,426**
	Meters	-	15	95	226	685	1,015	**2,036**
	MDMS	362	593	603	563	575	1,106	**3,802**
	Network	-	266	549	852	1,083	1,412	**4,162**
	Total	**362**	**874**	**1,247**	**1,641**	**3,277**	**5,025**	**12,426**

Table 3 - All AMI Project Costs (in $000s)

ALL COSTS - IMPLEMENTATION & OPERATING (in $000s)		2010	2011	2012	2013	2014	2015	TOTAL
HECO	Proj Mgmt	855	881	909	928	934	954	**5,461**
	Meters	-	14,994	15,331	15,728	660	718	**47,431**
	MDMS	5,668	4,647	1,615	533	388	746	**13,597**
	Network	54	350	616	919	901	934	**3,774**
	Total	**6,577**	**20,872**	**18,471**	**18,108**	**2,883**	**3,352**	**70,263**
MECO	Proj Mgmt	292	301	345	600	811	538	**2,887**
	Meters	-	-	-	-	11,761	262	**12,023**
	MDMS	1,255	1,029	358	118	86	165	**3,011**
	Network	12	3	3	3	269	210	**500**
	Total	**1,559**	**1,333**	**706**	**721**	**12,927**	**1,175**	**18,421**
HELCO	Proj Mgmt	292	288	320	279	535	549	**2,263**
	Meters	-	-	-	-	-	15,446	**15,446**
	MDMS	1,481	1,214	422	139	101	195	**3,552**
	Network	14	4	4	4	4	389	**419**
	Total	**1,787**	**1,506**	**746**	**422**	**640**	**16,579**	**21,680**
TOTAL	Proj Mgmt	1,439	1,470	1,574	1,807	2,280	2,041	**10,611**
	Meters	-	14,994	15,331	15,728	12,421	16,426	**74,900**
	MDMS	8,404	6,890	2,395	790	575	1,106	**20,160**
	Network	80	357	623	926	1,174	1,533	**4,693**
	Total	**9,923**	**23,711**	**19,923**	**19,251**	**16,450**	**21,106**	**110,364**

Table 4 - AMI Project Management Costs (in $000s)

PROJECT MANAGEMENT (in $000s)		2010	2011	2012	2013	2014	2015	TOTAL
Project Management								
Internal Labor Expense	HECO	855	881	909	928	934	954	**5,461**
	MECO	52	54	91	341	555	276	**1,369**
	HELCO	35	23	47	-	260	268	**633**
	Total	**942**	**958**	**1,047**	**1,269**	**1,749**	**1,498**	**7,463**
All Other Expense	HECO	-	-	-	-	-	-	-
	MECO	240	247	254	259	256	262	**1,518**
	HELCO	257	265	273	279	275	281	**1,630**
	Total	**497**	**512**	**527**	**538**	**531**	**543**	**3,148**
TOTAL	HECO	855	881	909	928	934	954	**5,461**
	MECO	292	301	345	600	811	538	**2,887**
	HELCO	292	288	320	279	535	549	**2,263**
	Total	**1,439**	**1,470**	**1,574**	**1,807**	**2,280**	**2,041**	**10,611**

Table 5 - AMI Project Meter Costs (in $000s)

METERS (in $000s)		2010	2011	2012	2013	2014	2015	TOTAL
AMI Meter Material Cost								
Capital	HECO	-	10,225	10,303	10,384	241	243	**31,396**
	MECO	-	-	-	-	7,605	122	**7,727**
	HELCO	-	-	-	-	-	9,626	**9,626**
	Total	-	**10,225**	**10,303**	**10,384**	**7,846**	**9,991**	**48,749**
AMI Meter Installation								
Capital	HECO	-	2,379	2,468	2,560	75	77	**7,559**
	MECO	-	-	-	-	2,418	51	**2,469**
	HELCO	-	-	-	-	-	3,158	**3,158**
	Total	-	**2,379**	**2,468**	**2,560**	**2,493**	**3,286**	**13,186**
Damaged AMI Meter Replacement Material								
Capital	HECO	-	-	49	148	248	299	**744**
	MECO	-	-	-	-	-	37	**37**
	HELCO	-	-	-	-	-	-	-
	Total	-	-	**49**	**148**	**248**	**336**	**781**
Damaged AMI Meter Replacement Installation								
Capital	HECO	-	15	46	78	96	99	**334**
	MECO	-	-	-	-	25	52	**77**
	HELCO	-	-	-	-	-	35	**35**
	Total	-	**15**	**46**	**78**	**121**	**186**	**446**
Replacing Damaged Meter Sockets								
Expense	HECO	-	2,375	2,465	2,558	-	-	**7,398**
	MECO	-	-	-	-	1,713	-	**1,713**
	HELCO	-	-	-	-	-	2,627	**2,627**
	Total	-	**2,375**	**2,465**	**2,558**	**1,713**	**2,627**	**11,738**
TOTAL	HECO	-	14,994	15,331	15,728	660	718	**47,431**
	MECO	-	-	-	-	11,761	262	**12,023**
	HELCO	-	-	-	-	-	15,446	**15,446**
	Total	-	**14,994**	**15,331**	**15,728**	**12,421**	**16,426**	**74,900**

Table 6 - AMI Network Costs (in $000s)

AMI NETWORK (in $000s)		2010	2011	2012	2013	2014	2015	TOTAL
FNP/FRP Material & Installation								
Capital	HECO	-	68	51	51	-	-	**170**
	MECO	-	-	-	-	68	-	**68**
	HELCO	-	-	-	-	-	101	**101**
	Total	**-**	**68**	**51**	**51**	**68**	**101**	**339**
Sensus FlexNet Network Lease								
Expense	HECO	-	266	549	852	885	918	**3,470**
	MECO	-	-	-	-	198	207	**405**
	HELCO	-	-	-	-	-	284	**284**
	Total	**-**	**266**	**549**	**852**	**1,083**	**1,409**	**4,159**
Sensus Additional Options								
Expense	HECO	54	16	16	16	16	16	**134**
	MECO	12	3	3	3	3	3	**27**
	HELCO	14	4	4	4	4	4	**34**
	Total	**80**	**23**	**23**	**23**	**23**	**23**	**195**
TOTAL	HECO	54	350	616	919	901	934	**3,774**
	MECO	12	3	3	3	269	210	**500**
	HELCO	14	4	4	4	4	389	**419**
	Total	**80**	**357**	**623**	**926**	**1,174**	**1,533**	**4,693**

Table 7 – AMI MDMS Costs by Phases (in $000s)

MDMS (in $000s)		2010	2011	2012	2013	2014	2015	TOTAL
MDMS Hardware and Operating System (including AFUDC)								
Capital	HECO	417	265	-	-	-	344	**1,026**
	MECO	93	59	-	-	-	76	**228**
	HELCO	110	70	-	-	-	90	**270**
	Total	**620**	**394**	-	-	-	**510**	**1,524**
Phase I - Basic CIS and RNI Integration (including AFUDC)								
Deferred	HECO	4,252	-	-	-	-	-	**4,252**
	MECO	940	-	-	-	-	-	**940**
	HELCO	1,110	-	-	-	-	-	**1,110**
	Total	**6,302**	-	-	-	-	-	**6,302**
Phase II - Additional Integration Tasks (including AFUDC)								
Deferred	HECO	-	3,276	-	-	-	-	**3,276**
	MECO	-	724	-	-	-	-	**724**
	HELCO	-	855	-	-	-	-	**855**
	Total	-	**4,855**	-	-	-	-	**4,855**
Phase III - Additional Customization (including AFUDC)								
Deferred	HECO	-	-	904	-	-	-	**904**
	MECO	-	-	201	-	-	-	**201**
	HELCO	-	-	236	-	-	-	**236**
	Total	-	-	**1,341**	-	-	-	**1,341**
MDMS Software License Fee								
Deferred	HECO	215	167	167	153	-	-	**702**
	MECO	48	37	37	34	-	-	**156**
	HELCO	56	44	44	40	-	-	**184**
	Total	**319**	**248**	**248**	**227**	-	-	**1,042**
Training, Process & Change Management								
Expense	HECO	540	539	137	-	-	-	**1,216**
	MECO	120	120	30	-	-	-	**270**
	HELCO	141	141	36	-	-	-	**318**
	Total	**801**	**800**	**203**	-	-	-	**1,804**
Support and Maintenance								
Expense	HECO	244	400	407	380	388	402	**2,221**
	MECO	54	89	90	84	86	89	**492**
	HELCO	64	104	106	99	101	105	**579**
	Total	**362**	**593**	**603**	**563**	**575**	**596**	**3,292**
TOTAL	Capital	620	394	-	-	-	510	**1,524**
	Deferred	6,621	5,103	1,589	227	-	-	**13,540**
	Expense	1,163	1,393	806	563	575	596	**5,096**
	Total	**8,404**	**6,890**	**2,395**	**790**	**575**	**1,106**	**20,160**

Table 8 – AMI MDMS Costs by Accounting Stages (in 000s)

MDMS (in $000s)		2010	2011	2012	2013	2014	2015	TOTAL
STAGE 1 - Preliminatry Project Stage								
Expense	HECO	**All Stage 1 MDMS costs are expensed within the 2009 Budget Year**						
	MECO							
	HELCO							
	Total	-	-	-	-	-	-	-
STAGE 2 - Application Development Stage								
Deferred (including AFUDC)	HECO	4,467	3,443	1,071	153	-	-	**9,134**
	MECO	988	761	238	34	-	-	**2,021**
	HELCO	1,166	899	280	40	-	-	**2,385**
	Total	**6,621**	**5,103**	**1,589**	**227**	-	-	**13,540**
Expense	HECO	540	539	137	-	-	-	**1,216**
	MECO	120	120	30	-	-	-	**270**
	HELCO	141	141	36	-	-	-	**318**
	Total	**801**	**800**	**203**	-	-	-	**1,804**
Total		**7,422**	**5,903**	**1,792**	**227**	-	-	**15,344**
STAGE 3 - Post Implementation/Operation Stage								
Expense	HECO	244	400	407	380	388	402	**2,221**
	MECO	54	89	90	84	86	89	**492**
	HELCO	64	104	106	99	101	105	**579**
	Total	**362**	**593**	**603**	**563**	**575**	**596**	**3,292**
Capital (including AFUDC)	HECO	417	265	-	-	-	344	**1,026**
	MECO	93	59	-	-	-	76	**228**
	HELCO	110	70	-	-	-	90	**270**
	Total	**620**	**394**	-	-	-	**510**	**1,524**
TOTAL	HECO	5,668	4,647	1,615	533	388	746	**13,597**
	MECO	1,255	1,029	358	118	86	165	**3,011**
	HELCO	1,481	1,214	422	139	101	195	**3,552**
	Total	**8,404**	**6,890**	**2,395**	**790**	**575**	**1,106**	**20,160**

Table 9 – AMI Capital Costs (in $000s)

CAPITAL COSTS (in $000s)		2010	2011	2012	2013	2014	2015	TOTAL
Meters								
AMI Meter Material Cost	HECO	-	10,225	10,303	10,384	241	243	**31,396**
	MECO	-	-	-	-	7,605	122	**7,727**
	HELCO	-	-	-	-	-	9,626	**9,626**
	Total	-	**10,225**	**10,303**	**10,384**	**7,846**	**9,991**	**48,749**
AMI Meter Installation	HECO	-	2,379	2,468	2,560	75	77	**7,559**
	MECO	-	-	-	-	2,418	51	**2,469**
	HELCO	-	-	-	-	-	3,158	**3,158**
	Total	-	**2,379**	**2,468**	**2,560**	**2,493**	**3,286**	**13,186**
Damaged AMI Meter Replacement Material Cost	HECO	-	-	49	148	248	299	**744**
	MECO	-	-	-	-	-	37	**37**
	HELCO	-	-	-	-	-	-	-
	Total	-	-	**49**	**148**	**248**	**336**	**781**
Damaged AMI Meter Replacement Installation	HECO	-	15	46	78	96	99	**334**
	MECO	-	-	-	-	25	52	**77**
	HELCO	-	-	-	-	-	35	**35**
	Total	-	**15**	**46**	**78**	**121**	**186**	**446**
MDMS Development & Implementation								
MDMS Hardware & Oper. System (incl. AFUDC)	HECO	417	265	-	-	-	344	**1,026**
	MECO	93	59	-	-	-	76	**228**
	HELCO	110	70	-	-	-	90	**270**
	Total	**620**	**394**	-	-	-	**510**	**1,524**
AMI Communications Network								
FNP/FRP Material & Installation	HECO	-	68	51	51	-	-	**170**
	MECO	-	-	-	-	68	-	**68**
	HELCO	-	-	-	-	-	101	**101**
	Total	-	**68**	**51**	**51**	**68**	**101**	**339**
TOTAL CAPITAL	HECO	417	12,952	12,917	13,221	660	1,062	**41,229**
	MECO	93	59	-	-	10,116	338	**10,606**
	HELCO	110	70	-	-	-	13,010	**13,190**
	Total	**620**	**13,081**	**12,917**	**13,221**	**10,776**	**14,410**	**65,025**

Table 10 – AMI Deferred Costs (in $000s)

DEFERRED COSTS (in $000s)		2010	2011	2012	2013	2014	2015	TOTAL
MDMS Development & Implementation								
MDMS Application SW License Fees	HECO	215	167	167	153	-	-	**702**
	MECO	48	37	37	34	-	-	**156**
	HELCO	56	44	44	40	-	-	**184**
	Total	**319**	**248**	**248**	**227**	-	-	**1,042**
Phase 1 MDMS SW (incl. AFUDC)	HECO	4,252	-	-	-	-	-	**4,252**
	MECO	940	-	-	-	-	-	**940**
	HELCO	1,110	-	-	-	-	-	**1,110**
	Total	**6,302**	-	-	-	-	-	**6,302**
Phase 2 MDMS SW (incl. AFUDC)	HECO	-	3,276	-	-	-	-	**3,276**
	MECO	-	724	-	-	-	-	**724**
	HELCO	-	855	-	-	-	-	**855**
	Total	-	**4,855**	-	-	-	-	**4,855**
Phase 3 MDMS SW (incl. AFUDC)	HECO	-	-	904	-	-	-	**904**
	MECO	-	-	201	-	-	-	**201**
	HELCO	-	-	236	-	-	-	**236**
	Total	-	-	**1,341**	-	-	-	**1,341**
TOTAL DEFERRED	HECO	4,467	3,443	1,071	153	-	-	**9,134**
	MECO	988	761	238	34	-	-	**2,021**
	HELCO	1,166	899	280	40	-	-	**2,385**
	Total	**6,621**	**5,103**	**1,589**	**227**	-	-	**13,540**

Table 11 – AMI Expense Costs (in $000s)

EXPENSE COSTS (in $000s)		2010	2011	2012	2013	2014	2015	TOTAL
Project Management								
Project Management	HECO	855	881	909	928	934	954	**5,461**
	MECO	292	301	345	600	811	538	**2,887**
	HELCO	292	288	320	279	535	549	**2,263**
	Total	**1,439**	**1,470**	**1,574**	**1,807**	**2,280**	**2,041**	**10,611**
Meters								
Replacing Damaged Meter Sockets	HECO	-	2,375	2,465	2,558	-	-	**7,398**
	MECO	-	-	-	-	1,713	-	**1,713**
	HELCO	-	-	-	-	-	2,627	**2,627**
	Total	**-**	**2,375**	**2,465**	**2,558**	**1,713**	**2,627**	**11,738**
MDMS Development & Implementation								
Training, Process & Change Management	HECO	540	539	137	-	-	-	**1,216**
	MECO	120	120	30	-	-	-	**270**
	HELCO	141	141	36	-	-	-	**318**
	Total	**801**	**800**	**203**	**-**	**-**	**-**	**1,804**
Support & Maintenance	HECO	244	400	407	380	388	402	**2,221**
	MECO	54	89	90	84	86	89	**492**
	HELCO	64	104	106	99	101	105	**579**
	Total	**362**	**593**	**603**	**563**	**575**	**596**	**3,292**
AMI Communications Network								
Sensus FlexNet Network	HECO	-	266	549	852	885	918	**3,470**
	MECO	-	-	-	-	198	207	**405**
	HELCO	-	-	-	-	-	284	**284**
	Total	**-**	**266**	**549**	**852**	**1,083**	**1,409**	**4,159**
Sensus Additional Options	HECO	54	16	16	16	16	16	**134**
	MECO	12	3	3	3	3	3	**27**
	HELCO	14	4	4	4	4	4	**34**
	Total	**80**	**23**	**23**	**23**	**23**	**23**	**195**
TOTAL EXPENSED	HECO	1,693	4,477	4,483	4,734	2,223	2,290	**19,900**
	MECO	478	513	468	687	2,811	837	**5,794**
	HELCO	511	537	466	382	640	3,569	**6,105**
	Total	**2,682**	**5,527**	**5,417**	**5,803**	**5,674**	**6,696**	**31,799**

Table 12 – AMI Quantifiable Benefits (in $000s)

QUANTIFIABLE BENEFITS (in $000s)		2010	2011	2012	2013	2014	2015	TOTAL
Meter Reading Savings	HECO	-	-	1,123	2,385	3,238	3,354	**10,100**
	MECO	-	-	-	-	-	875	**875**
	HELCO	-	-	-	-	-	-	-
	Total	-	-	**1,123**	**2,385**	**3,238**	**4,229**	**10,975**
Field Services Savings	HECO	-	157	322	496	1,022	1,053	**3,050**
	MECO	-	-	-	-	171	352	**523**
	HELCO	-	-	-	-	-	325	**325**
	Total	-	**157**	**322**	**496**	**1,193**	**1,730**	**3,898**
Energy Theft Recovery	HECO	-	290	886	1,487	1,799	1,817	**6,279**
	MECO	-	-	-	-	224	454	**678**
	HELCO	-	-	-	-	-	260	**260**
	Total	-	**290**	**886**	**1,487**	**2,023**	**2,531**	**7,217**
Meter Accuracy Gains	HECO	-	262	803	1,347	-	-	**2,412**
	MECO	-	-	-	-	233	475	**708**
	HELCO	-	-	-	-	-	304	**304**
	Total	-	**262**	**803**	**1,347**	**233**	**779**	**3,424**
TOTAL QUANTIFIABLE BENEFITS	HECO	-	709	3,134	5,715	6,059	6,224	**15,576**
	MECO	-	-	-	-	628	2,156	**2,784**
	HELCO	-	-	-	-	-	889	**889**
	Total	-	**709**	**3,134**	**5,715**	**6,687**	**9,269**	**25,514**

REIP Program

In their Final Statement of Position ("FSOP") filed in the renewable portfolio standards ("RPS") docket, Docket No. 2007-0008 on October 12, 2007, the Companies discussed the need to facilitate and accelerate the development of Hawaii's abundant renewable resources in order to further our State's goal of energy independence while addressing a compelling global mandate to reduce greenhouse gas emissions. The Companies further explained that one of the greatest challenges to the development of renewable energy in Hawaii, as well as in the nation, is the lack of infrastructure to support renewable energy resources.[1] As a result, Hawaii's RPS law explicitly points to factors impacting utility system reliability and stability, such as the impact of electricity generated from renewable energy resources.[2]

On October 12, 2007, the HECO Companies, Kauai Island Utility Cooperative, the Consumer Advocate and Hawaii Renewable Energy Alliance (collectively, the "Stipulating Parties") also filed a Stipulation and Joint RPS Framework ("Stipulated Framework"), which included among other things, the HECO Companies' proposed Renewable Energy Infrastructure Program ("REI Program") to encourage the development of renewable energy infrastructure projects that encourage renewable choices and/or otherwise enhance renewable energy choices for customers.

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[1] RPS FSOP at 6. In July of 2006, a report was issued in Washington, D.C. entitled Siting Renewable Energy Facilities. One of its principal conclusions was that one of the greatest challenges to the development of renewable energy nationwide is the lack of infrastructure to support it. Id.

[2] See RPS Preliminary Statement of Position at 31; RPS FSOP at 23-24. Under HRS § 269-95, the studies to be conducted by December 31, 2007, must include findings and recommendations regarding the "capability of Hawaii's electric utility companies to achieve renewable portfolio standards in a cost-effective manner, and shall assess factors such as the impact on consumer rates, utility system reliability and stability, costs and availability of appropriate renewable energy resources and technologies, permitting approvals, impacts on the economy, culture, community, environment, land and water, demographics, and other factors deemed appropriate by the commission . . . ."

In connection with the REI Program, the Stipulating Parties proposed a temporary REI Program Surcharge ("REIP Surcharge") to facilitate the recovery of renewable energy infrastructure project costs (including AMI Project costs) on a more timely basis than is afforded by the traditional rate case process.[3] See RPS FSOP at 7-9.[4] (The Companies' RPS FSOP contains a detailed discussion of legislative and other support for the REI Program and REIP Surcharge, which discussion is incorporated by reference herein. See RPS FSOP at 32-42.) On December 20, 2007, the Commission issued Order No. 23913, which initiated a separate docket, Docket No. 2007-0416, to examine the HECO Companies' proposed REI Program and REIP Surcharge.[5]

The Commission held public hearings on May 5, 2008 in Honolulu, May 7, 2008 in Hilo, May 8, 2008 in Kona, May 12, 2008 in Kaunakakai, May 14, 2008 in Kahului, and May 15, 2008 in Lanai City, thereby providing full public notice of and opportunity to provide input on the Companies' proposed REI Program. At these public hearings, members of the public provided testimony to the Commission on matters related to the REI Program, as well as other matters.

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[3] See also HECO T-1, Docket No. 2008-0083, wherein HECO pointed out that the returns that HECO has actually earned have been much lower than those used to establish rates in its recent rate cases because: (1) although interim rate orders in HECO's most recent rate cases have been issued within the time frames set by law, the lag between the start of the test year and the interim rate relief has not allowed HECO the opportunity to actually earn the allowed return in the test year; (2) kilowatt hour sales were lower than forecast in the rate cases, resulting in insufficient revenue dollars and deteriorated returns; and (3) costs are increasing substantially faster than the revenues received to pay for those costs.

[4] See also Mark Newton Lowry, PhD, Alternative Regulation for Infrastructure Cost Recovery, Pacific Economics Group, January 9, 2007 (detailing the kinds of barriers created by traditional cost of service regulation; explaining that major plant additions, particularly generation and transmission investments, can involve sizable rate increases and a substantial risk of hindsight prudence disallowances and stranded costs, resulting in a marked increase in operating risk unlikely to be matched by a higher rate of return; and concluding that utilities, commissions and consumers have a shared interest in pursuing alternative forms of regulation in order to help the electric power industry ensure high levels of reliability, service quality and economic efficiency in a era of turbulent business conditions and mounting investment needs).

[5] The REI Program proposal includes a proposed consolidation incentive mechanism that would allow the HECO Companies to recover certain costs for renewable projects built on the islands of Hawaii and Maui from Oahu ratepayers. However, the HECO Companies are not seeking through this Application to shift the costs of the AMI Project interisland.

Statements of position were filed by HREA and LOL dated July 28, 2008, and by the Consumer Advocate dated July 29, 2008. In its statement of position, the Consumer Advocate recommended approval of the REI Program and REIP Surcharge mechanism. HREA also supported the REI Program and REIP Surcharge mechanism. LOL, "[a]fter thoughtful review . . . d[id] not oppose this mechanism" either. Subsequently, by letters dated August 12, 2008, the HECO Companies and the Consumer Advocate informed that Commission that they would not be submitting information requests on the other Parties' statements of position.

On September 17, 2008, the HECO Companies filed their Reply Position Statement ("Reply") in the REIP docket, and attached their Proposed REI Program Framework thereto as Exhibit B. By letter dated October 22, 2008 the Companies informed the Commission that the parties to the REIP docket, among other things: (1) have reached an agreement on all of the issues in the REIP docket; (2) agree that it is appropriate that the Commission approve the HECO Companies' proposed REI Program and related REIP Surcharge, as provided in Exhibit B to the HECO Companies' Reply; (3) agree that the record in the REIP docket is complete; and (4) waived an evidentiary hearing with respect to the REIP docket.

Accordingly, in this AMI Project Application, the Companies are seeking authorization from the Commission to defer AMI Project costs and recover such costs through the proposed REIP Surcharge, as pursuant to the respectfully requested REI Program proposed in Docket 2007-0416, or in the alternative, through a specifically dedicated AMI Surcharge.

EXHIBIT 21 - Rate Impact of AMI

Hawaiian Electric Company, Inc.

	2010	2011	2012	2013	2014	2015
Rev Requirement ($000)	6,198	11,125	12,299	7,906	5,988	5,141
Sales Forecast (GWH)	7,464.5	7,505.8	7,608.4	7,727.1	7,850.0	7,974.9
AMI Surcharge (¢/kWh):	**0.0830**	**0.1482**	**0.1617**	**0.1023**	**0.0763**	**0.0645**

Sales Forecast:
Yrs 2010 - 2013: Forecast Division based on September 2008 Forecast.
Yrs 2014 - 2015: Forecast Division based on escalated growth rate from August 2007 LT Forecast.

Hawaii Electric Light Company, Inc.

	2010	2011	2012	2013	2014	2015
Rev Requirement ($000)	2,471	2,750	2,641	2,468	2,300	4,476
Sales Forecast (GWH)	1,161.4	1,184.4	1,210.8	1,240.8	1,264.6	1,282.7
AMI Rate Impact (¢/kWh):	**0.2128**	**0.2322**	**0.2181**	**0.1989**	**0.1819**	**0.3490**

Sales Forecast:
Yrs 2010 - 2013: Forecast Division based on September 2008 Forecast.
Yrs 2014 - 2015: Generation Planning extrapolated forecast.

Maui Electric Company, Ltd. (Maui Division)

	2010	2011	2012	2013	2014	2015
Rev Requirement ($000)	1,842	2,033	1,994	1,882	3,422	1,199
Sales Forecast (GWH)	1,200.5	1,236.2	1,276.8	1,297.4	1,323.4	1,352.0
AMI Rate Impact (¢/kWh):	**0.1534**	**0.1645**	**0.1562**	**0.1451**	**0.2586**	**0.0887**

Sales Forecast:
Yrs 2010 - 2015: Forecast Division based on September 2008 Forecast.

Source:
Revenue Requirement: Finanical Analysis Division
Total project revenue requirement less imputed debt and rebalancing costs and internal labor.

Revenue Requirement Calculation

The purpose of this exhibit is to present a narrative description of the revenue requirement calculation and the significant assumptions used. The revenue requirements are summarized on page 7 for HECO, MECO and HELCO for the years 2010 through 2015. The exhibits illustrate the net incremental revenue requirement of the AMI Project calculated for each of the three Companies. As previously described, the proposed AMI Surcharge is to allow for recovery of the net revenue requirement impact of the major AMI components and the offsetting incremental benefits. The revenue requirement of the capital investment, deferred costs and expenses of the major AMI components was calculated along with the revenue requirement of the offsetting incremental benefits. The aggregate of these two calculated revenue requirements represent the net incremental revenue requirement. The assumptions supporting the summaries are described below and also provided on page 8.

Revenue Requirement

A simplified definition of a revenue requirement is that it is a calculated value which represents the estimated revenues needed from ratepayers which would allow the Company to recover its capital investment and expenses, honor its debt obligations, pay its revenue and income tax liabilities and pay its preferred shareholders while providing a fair return to its common shareholders for their investment. Generally, the structure and major components included in the revenue requirement calculation and model are consistent and similar, in many respects, from project to project and across all Companies as the calculation needs to capture the impact from the above listed items. However, each calculation and model is modified for each project to specifically capture any factors or assumptions related to that particular project (e.g. renewable tax credits for a renewable energy project).

The following describe in more detail the individual components contained within the revenue requirement calculation for the AMI Project.

1. **General Assumptions** – Generally, certain simplifying assumptions are made in all revenue requirement calculations. While an attempt is made to accurately model the revenue requirement calculation to match the project, it is not always possible to accurately capture the realities surrounding any particular project. The revenue requirement calculation is based on the most recently available project estimates and assumptions.

   Revenue requirement calculations are generally modeled to provide annual revenue requirements over the estimated service life of the project or capital investment and utilize the annual average rate base. Use of an average rate base, which is the average of the beginning of year and ending of year balance, is consistent with the methodology employed in rate cases and generally used in most revenue requirement calculations. The use of an annual average rate base helps account for variations in the timing of events happening within a year and helps simplify the mechanics of the calculation.

2. **Accounting, Tax and Ratemaking Treatment** – The revenue requirements calculation will generally model the expected accounting, tax and ratemaking treatment expected for the project or capital investment. This is based on the current tax and accounting rules and the expected ratemaking treatment determined for the project or capital investment at that time. The revenue requirement calculation for the AMI Project incorporates the proposed accounting and ratemaking treatment as described in Section XI of the Application.

3. **Capital Structure and Financing Costs** – The capital structure used in the AMI Project revenue requirement calculation assumes financing of 3% short-term debt, 36% revenue bond financing, 7% preferred stock and the remaining 54% common stock. The costs to finance are assumed as 6% for short-term debt, 6.5% for revenue bond financing, 8% for preferred stock and 12% for common stock. This results in a weighted average cost of capital of 9.56% and an after-tax weighted average cost of capital of 8.58%. The Companies generally utilize this capital structure for long-term planning purposes. It is based on the Companies forecast of the incremental capital costs on average over 10+ years.
4. **Income Taxes** – The Companies assumed a federal tax rate of 35% (32.89% effective) and a state tax rate of 6.4% (6.02% effective). The total effective tax rate assumed is 38.91%.
5. **Revenue Taxes** – The Companies are subject to the following revenue taxes: 1) Public Service Company Tax of 5.885%; 2) Franchise Tax of 0.5%; and 3) Public Utility Fee of 2.5%. This results in a composite revenue tax rate of 8.885%.
6. **Capital Investment and Return on Investment** – The capital investments in the AMI Project are assumed to be placed in rate base in the year they are deemed "used or useful". The timing and amounts of capital investment are shown in Section X of the Application. The return on investment is based on the average net capital investment in rate base and the assumed capital structure and costs of financing as previously discussed.
7. **Book Depreciation and Tax Depreciation** – Depreciation allows for the return of the capital investment in rate base. Depreciation begins in the year after the capital investment is assumed to be placed in service. This is consistent with the current

methodology followed by the Companies for book accounting purposes. For the revenue requirement calculation book depreciation is calculated on a straight-line basis based on the capital investment and the estimated service life of the capital investment. The estimated service life assumed in the revenue requirement calculation may differ from the actual book depreciation rates used. For the AMI Project, the revenue requirement calculation is performed for each of the three Companies. As each Company has their own book depreciation rates based on their own depreciation studies, the estimated service life assumptions may differ between Companies. In order to simplify the assumptions used and to allow for comparability between the calculations for each of the three Companies, the estimated service life assumptions were kept consistent in the calculations between the Companies.

8. **Tax Depreciation** - For tax purposes depreciation begins in the year the capital investment is assumed to be placed in service. This is consistent with the current tax treatment of capital investments. For the AMI Project revenue requirement calculation, the Companies assumed a 10-year accelerated recovery period and 150-percent declining balance method which were approved in The Emergency Economic Stabilization Act of 2008. Tax depreciation is calculated based on the capital investment and the tax depreciation rates applicable to that particular capital investment. Accelerated tax depreciation is available for capital investments that are not financed with tax exempt revenue bonds. Capital investments financed with tax exempt revenue bonds are subject to straight line tax depreciation. The revenue requirement model adjusts the tax depreciation calculation to take into account the proposed capital structure and any assumed tax exempt revenue bond financing.

9. **Accelerated Recovery of Capital Investment** – For certain AMI Project capital components it is assumed the recovery of the investment in these components is "accelerated" over a shorter time period than those capital components would normally be depreciated for book accounting purposes. For purposes of the revenue requirement calculation the accelerated recovery is calculated on a straight line basis based on the capital investment and the proposed accelerated recovery period. This accelerated recovery results in the recording of a regulatory liability to be included as a deduction in rate base. The accelerated recovery and proposed ratemaking treatment is further discussed in Section XI of the Application.
10. **Project Expenses** – Project expenses are recognized and recorded in the year they're incurred. This is consistent with the current methodology followed by the Companies for book accounting purposes. The timing and amounts of project expenses are shown in Section X of the Application.
11. **Deferred Software Development Costs and Amortization** – As described in Section XI of the Application, the Companies request that software development costs be allowed to be deferred and amortized over a 12 year period. Deferred software development costs are assumed to be placed in rate base upon going into service with amortization beginning the following month. As the revenue requirements are calculated on an annual basis, the Companies made a simplifying assumption that the software will go into service at the end of a year, with amortization beginning the following year. The timing and amounts of deferred software development costs are shown in Section X of the Application.

12. **Deferred Income Taxes** – A deferred tax asset or liability represents the increase or decrease in taxes payable or refundable in future years as a result of temporary differences in the current year. In the revenue requirement calculation the primary temporary difference which drives the deferred taxes is the difference in the book and tax treatment of depreciation and the difference in the book and tax treatment of the State Investment Tax Credit. In each year the differences in the annual book depreciation and tax depreciation are determined and the effective income tax rate is applied to determine the deferred income tax.

13. **State Investment Tax Credit** – A 4% State Investment Tax Credit is available for capital investments. For book accounting purposes, this credit is deferred with future recognition based on straight line annual amortization of the deferred balance at the book depreciation rate of the capital investment. In effect, the recognition of the credit is deferred in order to match the use of the capital investment which is based on the straight line book depreciation. For tax purposes, this credit is taken in the year in which the capital investment is made and the utility asset is placed in service. This results in a temporary difference and a related deferred income tax asset.

HECO COMPANIES NET INCREMENTAL REVENUE REQUIREMENT CALCULATION

	Year	Project Mgmt	Replace/ Retire Existing Meters	New Meter Installation	MDMS Deferred SW Development	MDMS Capital & Expense	Damaged Socket Replacement	AMI Network: AMI Network Cap & Exp	AMI Network: Imputed Debt	AMI Network: Total Rev. Reqmt.	Direct Benefits: Field Service Savings	Direct Benefits: Meter Reading Savings	Direct Benefits: Meter Accuracy	Direct Benefits: Electricity Theft	TOTAL: Revenue Requirements
		A	B	C	D	E	F	G	H	I = G=H	J	K	L	M	A+B+C+D+E+ F+I+J+K+L+M
HECO AMI															
Revenue Requirements - SURCHARGE REVENUE REQUIREMENT															
($000)															
1	**2010**	-	4,918	-	329	891	-	60	-	60	-	-	-	-	6,198
2	**2011**	-	4,710	1,785	1,273	1,216	2,606	314	-	314	(172)	-	(288)	(318)	11,125
3	**2012**	-	4,320	5,384	1,825	856	2,705	651	-	651	(354)	(1,233)	(882)	(973)	12,299
4	**2013**	-	(969)	8,781	1,901	657	2,808	1,001	-	1,001	(544)	(2,618)	(1,479)	(1,632)	7,906
5	**2014**	-	(1,041)	10,175	1,815	639	-	1,050	-	1,050	(1,122)	(3,553)	-	(1,974)	5,988
6	**2015**	-	(925)	9,565	1,707	545	-	1,081	-	1,081	(1,155)	(3,682)	-	(1,994)	5,141
	Total	-	11,013	35,690	8,848	4,803	8,119	4,155	-	4,155	(3,347)	(11,085)	(2,648)	(6,891)	48,657
MECO AMI															
Revenue Requirements - SURCHARGE REVENUE REQUIREMENT															
($000)															
1	**2010**	263	1,296	-	73	198	-	13	-	13	-	-	-	-	1,842
2	**2011**	271	1,207	-	281	270	-	4	-	4	-	-	-	-	2,033
3	**2012**	279	1,118	-	403	190	-	4	-	4	-	-	-	-	1,994
4	**2013**	285	1,027	-	420	146	-	4	-	4	-	-	-	-	1,882
5	**2014**	282	(239)	1,420	401	142	1,880	226	-	226	(188)	-	(256)	(245)	3,422
6	**2015**	287	(353)	2,875	378	121	-	258	-	258	(386)	(960)	(521)	(499)	1,199
	Total	1,667	4,056	4,295	1,957	1,065	1,880	508	-	508	(574)	(960)	(777)	(744)	12,372
HELCO AMI															
Revenue Requirements - SURCHARGE REVENUE REQUIREMENT															
($000)															
1	**2010**	187	1,950	-	86	233	-	16	-	16	-	-	-	-	2,471
2	**2011**	294	1,802	-	332	317	-	4	-	4	-	-	-	-	2,750
3	**2012**	282	1,654	-	476	224	-	4	-	4	-	-	-	-	2,641
4	**2013**	291	1,505	-	496	172	-	4	-	4	-	-	-	-	2,468
5	**2014**	300	1,355	-	474	167	-	4	-	4	-	-	-	-	2,300
6	**2015**	306	(468)	1,819	445	142	2,883	324	-	324	(356)	-	(334)	(285)	4,476
	Total	1,660	7,798	1,819	2,309	1,255	2,883	357	-	357	(356)	-	(334)	(285)	17,106

AMI
Revenue Requirements Model
Assumptions

Manual input

Cost of Capital Assumptions	Weight	Rate	Weighted Average	After-Tax Weighted Average
Short Term Debt	3.00%	6.00%	0.18%	0.11%
Long Term Debt (Revenue Bonds)	36.00%	6.50%	2.34%	1.43%
Long Term Debt (Taxable Debt)	0.00%	0.00%	0.00%	0.00%
Preferred Stock	7.00%	8.00%	0.56%	0.56%
Common Stock	54.00%	12.00%	6.48%	6.48%
	100.00%		9.56%	8.579%

Tax Assumptions		Effective	
Federal Income Tax Rate	35.00%	32.89%	
State Income Tax Rate	6.40%	6.02%	
		38.91%	
State Investment Tax Credit (ITC)		4.00%	
Public Service Company Tax		5.885%	
PUC Fee		0.500%	
Franchise Tax		2.500%	
Composite Revenue Tax Rate		8.885%	1.09751

NEED FOR TIMELY COST RECOVERY

Further support for using the REIP Surcharge and other timely cost recovery mechanisms is described below.

a. HCEI Agreement

As discussed above, AMI is a critically component of a number of important aspects of the Hawaii Clean Energy Initiative. As a result, the HCEI Agreement specifically provides that the AMI "meters and associated costs will be paid for through the [Clean Energy Initiative Surcharge], until such costs are embedded and recovered in the utilities' base rates in future rate cases." HCEI Agreement at 24.

b. Timely Cost Recovery Mechanisms in Other Jurisdictions

Other state governments likewise have recognized the value of timely cost recovery as an incentive for the furtherance of renewable energy, and also for AMI. For example, Section 13(3) of the Oregon Renewable Energy Act ("SB 838") encourages the development of renewable energy infrastructure by directing the Public Utility Commission of the State of Oregon ("OPUC") to "establish an automatic adjustment clause . . . or another method that allows timely recovery of costs prudently incurred by an electric company to construct or otherwise acquire facilities that generate electricity from renewable energy sources or for associated electricity transmission."[1] Pursuant to SB 838, the OPUC adopted a stipulation on December 19, 2007, in which the OPUC Staff, Citizen's Utility Board ("CUB") and Industrial Customers of Northwest

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[1] Emphasis added. SB 838 was signed into law on June 6, 2007, in part, to "provide a comprehensive renewable energy policy for Oregon, enabling industry, government and all Oregonians to accelerate the transition to a more reliable and more affordable energy system . . . ." As used in SB 838, "'automatic adjustment clause' means a provision of a rate schedule that provides for rate increases or decreases, or both, without prior hearing, reflecting increases or decreases or both in costs incurred, taxes paid to units of government or revenues earned by a utility and that is subject to review by the commission at least once every two years." OR. REV. STAT. § 757.210; see SB 838 § 13(3).

Utilities ("ICNU") approved "Renewable Adjustment Clause" ("RAC") tariffs for Portland General Electric ("PGE") and PacifiCorp.[2]

In the more specific context of advanced metering, the OPUC recently approved PGE's AMI tariff application on May 5, 2008. See Re Portland General Electric Company's Request to Add Schedule 111, Advanced Metering Infrastructure (AMI), UE 189, Order No. 08-245 (May 5, 2008) ("Order 08-245").[3] In Order 08-245, the OPUC found that "the investment in AMI technology would be cost effective, even if it were simply a matter of substituting the new meters for the old (including the early retirement of the UE 115 meters)." Id. at 9. The OPUC further found that:

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[2] See OPUC Order No. 07-572, entered December 19, 2007 in UM 1330 ("Order 07-572"). As modified and adopted by the OPUC, the stipulation provides for the utilities' annual filing of "RAC schedules" for proposed charges relating to renewable resources, while preserving the right of other parties to review the proposed charges and challenge the prudence of the costs. Paragraph 6.b of the stipulation provides that:

> the RAC schedules will recover the actual and forecasted revenue requirement associated with prudently incurred costs of resources (including associated transmission) that are: (1) eligible under SB 838; (2) in service as of the date of the proposed change; and (3) approved by the Commission. The revenue requirement includes:
>
> - ☐ The return of and on capital costs of the renewable energy source and associated transmission;
> - ☐ Forecasted operation and maintenance costs;
> - ☐ Forecasted property taxes;
> - ☐ Forecasted energy tax credits; and
> - ☐ Other forecasted costs and cost offsets authorized by SB 838 and not captured in the Utility's annual power cost update.

Order 07-572 at 3.

[3] In approving PGE's AMI tariff, the OPUC adopted the settlement and stipulation entered into by PGE, staff of the OPUC ("Staff"), the Oregon Department of Energy ("ODOE") (PGE, Staff and ODOE are collectively referred to in Order 08-245 as the "Joint Parties"), the Community Action Partnership of Oregon, and Northwest Natural Gas Company imposing certain AMI conditions on PGE. See Order 08-245 at 1, 10. The AMI conditions generally pertain to operational implementation plans, customer and system-related benefits, demand response, distribution asset utilization, avoided service transformer failures, proper transformer sizing, delayed feeder conductor work, outage management, regulatory filings, coordination with Northwest Natural Gas Company in PGE's joint meter reading area, and issues related to the Community Action Partnership of Oregon and Oregon Energy Coordinators. See id. at 2; see also Proposed AMI Conditions (November 2007) attached to Order 08-245 as Appendix A.

CUB opposed adoption of the stipulation, however, arguing that "PGE's AMI Project is not based on a mature technology." More specifically, Order 08-245 notes CUB's concern "that PGE's AMI technology will not have the functionality to directly control load – 'one of the more exciting opportunities that advanced meters could provide." Id. at 5. In response to CUB's contention, the Joint Parties noted that it is highly likely that new features will be available in the future, but, if PGE were to wait for new technology, the AMI project might never be undertaken. See id. at 7.

> The technology may be used dynamically to generate much more substantial benefits through rate design and load control applications and other system and operational benefits. These benefits could not be realized without the deployment of the devices. To the extent that these measures likewise are cost effective, their realization likely would make the first stage economic, even if it were not cost effective by itself.

Id.

With respect to the need for timely recovery of AMI-related costs, PGE's AMI implementation schedule (including meter purchase and installation contracts), has been designed to recover AMI costs associated with (1) the deployment of new metering equipment only after the meters have been installed; (2) accelerated depreciation of existing metering equipment prior to the retirement of such equipment; and (3) O&M savings as the savings are being achieved.[4] In particular, PGE's implementation schedule collects from customers the revenue requirement impacts of: (1) accelerated depreciation over the two and a half year period between July 1, 2007 and December 31, 2009 of the PGE's replaced meters;[5] and (2) PGE's installed AMI facilities less O&M cost savings.[6]

Under PGE's AMI tariff, new meters, "which comprise over 80 percent of the investment, will 'immediately close to plant' when received by PGE." In addition, "The recovery of the new system incorporates a six-month lag in recovery of new AMI costs, with rate

[4] Under its AMI tariff, PGE's total AMI revenue requirement of $12.9 million is allocated into three components: (1) recovery of the costs of new equipment ($12.5M); (2) accelerated depreciation of existing meters ($4.5M); and (3) offsetting O&M savings ($4.1M). See id. at 3.

[5] Under Schedule 111, accelerated depreciation of old meters occurs faster than the rate of replacement. This is accomplished by applying most of the accelerated depreciation of the old system at the front end of the tariff. This also allows the revenue requirement to be levelized over the deployment period because cost recovery of the new system primarily occurs at the back end due to the averaging of a lagged rate base. See Order 08-245 at 4; Testimony submitted in UE 189/Joint/100 Schwartz – Owings – Tooman at 10-11. In support of this approach, the Joint Parties pointed out that the accelerated depreciation of old meters would be consistent with prior OPUC orders. See Order 08-245 at 4.

[6] See Advice No. 07-08, Advanced Metering Infrastructure (AMI), filed by PGE with the OPUC on March 7, 2007.

base adjusted monthly during the deployment period."[7] With respect to this approach, the OPUC observed that, "Without either the tariff or annual rate cases, PGE would receive no recovery on the new system during deployment." Order 08-245 at 3.

Similar efforts are underway in Delaware, where Delmarva Power and Light Company ("DP&L") has proposed mechanisms for timely cost recovery as part of its Comprehensive Demand-Side Management, Advanced Metering and Energy Efficiency Plan entitled, "Blueprint for the Future"[8] ("Blueprint"). Like PGE's AMI tariff, DP&L's Blueprint contains an "AMI Adjustment Mechanism" for the timely recovery between rate cases of capital costs associated with AMI. DP&L's AMI Adjustment Mechanism would be set annually on the basis of total project expenditures during the previous 12-month period.[9] In addition, Delmarva has proposed a timely AMI capital expenditure recovery period of 15 years, reflecting the expected life of the new equipment and the accelerated obsolescence rate of new technology.[10]

As noted above, in Order 679, FERC identified accelerated depreciation as a viable mechanism to encourage investment in transmission infrastructure because it provides improved cash flow and better positions public utilities for longer-term transmission investments. Accordingly, FERC has stated that it will consider, on a case-by-case basis, depreciable lives of less than 15 years because shorter depreciable lives may be appropriate in certain cases, such as advanced technologies for which the useful life is not necessarily known. See id., paras. 135-54.

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[7] Through 2010, the AMI will be part of PGE's rate base. After 2010, PGE will file a general rate case at the Commission's request that will capture the operating benefits on behalf of customers, if PGE is not already engaged in such a proceeding. See id. at 4.

[8] See Blueprint, filed February 6, 2007 in Docket No. 07-28 before the Public Service Commission of the State of Delaware.

[9] DP&L proposed to net any utility cost savings resulting from AMI deployment from the cost recovery sought each year. See Blueprint at 12.

[10] Similar to the utility's other investments, DP&L proposed an amortization period identical to expected equipment life. See id.

Indeed, Congress has considered depreciable lives for AMI assets that are substantially shorter than 15 years. For example, the Clean Renewable Energy and Conservation Tax Act, H.R. 2776, 110th Cong. (2007) seeks to amend the Internal Revenue Code of 1986 to provide tax incentives for the production of renewable energy and energy conservation. Section 1546 of the Act provides for a seven-year applicable recovery period for depreciation of "qualified energy management devices," including "any time-based meter which is capable of being used by the tax-payer as part of a system" that (1) "measures and records electricity usage data on a time-differentiated basis in at least 24 separate time segments per day"; (2) "provides for the exchange of information between supplier or provider and the customer's energy management device in support of time-based rates or other forms of demand response"; and (3) "provides data to such supplier or provider such that the supplier or provider can provide energy usage information to customers electronically". In other words, the seven-year depreciable life set forth in Section 1546 would apply to advanced meters.

With respect to DP&L's existing meters, DP&L's Blueprint proposes (in line with NARUC's Resolution on accelerated depreciation) "that the cost of retiring all existing meters and fully amortizing those costs be recovered through [an] AMI Adjustment Mechanism on an accelerated basis, not to exceed three to five years."[11] Under this proposal, interest on unrecovered capital costs would accrue at the utility's approved rate of return. As explained by DP&L, the AMI Adjustment Mechanism will serve to avoid delays in the recovery of significant capital costs that could otherwise have an adverse impact on the utility's cost of capital. See id.

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[11] Blueprint at 13. The Blueprint adds:

> The amount of AMI Adjustment Mechanism would vary by customer class, reflecting any AMI or smart thermostat cost differences. If the Commission approves the AMI Adjustment Mechanism, the monthly bill impact on customers after full AMI deployment is estimated to be $6.00 for each electric and gas customer. These costs will be offset by energy cost reductions, utility cost reductions and service quality improvements. Id.

The accelerated recovery of AMI-related costs is also being considered in New York, where Consolidated Edison Company of New York, Inc. ("Con Edison") and Orange and Rockland Utilities, Inc. ("Orange & Rockland") recently submitted their Plan for Development and Deployment of Advanced Electric and Gas Metering Infrastructure[12] ("AMI Plan") at the direction of the State of New York Public Service Commission ("NYPSC"). Covering a service territory of approximately 3.6 million meters, the AMI Plan is conditioned in part upon the utilities being given "a reasonable opportunity to recover all capital costs associated with the AMI and all incremental [O&M] expenses incurred in the implementation and operation of the AMI . . . ."[13]

Con Edison and Orange & Rockland have proposed to begin recovery of all AMI-related costs[14] contemporaneously with the initiation and implementation of their AMI pre-deployment demonstration projects. Specifically, the New York utilities have proposed to recover AMI-related costs from customers through annually reset surcharges until such time as the costs are placed in base rates.[15] In support of this cost recovery mechanism, the AMI Plan explains that:

> Because rates may be developed based on load information from the pre-deployment demonstration projects and other load research, the Companies should be permitted to recover lost electric and gas delivery revenues associated with customer participation in pilot rate programs that encourage reduction in customer usage. In addition, the Companies should be made revenue neutral for lost revenues during any transitional rate period.

AMI Plan at 43.

c. <u>FERC Order No. 679</u>

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[12] The AMI Plan was submitted on March 28, 2007 in NYPSC Case 94-E-0952 – In the Matter of Competitive Opportunities Regarding Electric Service, and Case 00-E-0165 – In the Matter of Competitive Metering.

[13] AMI Plan at 1.

[14] The "AMI-related costs" identified by Con Edison and Orange & Rockland include "the pre-deployment demonstration projects, to the extent not addressed in utility rate case orders . . . and all incremental O&M expenses incurred directly or indirectly in the implementation and operation of the AMI net of operational savings not yet accounted for in base rates." Id.

[15] Id. The AMI Plan proposed that each utility would "make an annual filing for carrying charges and expenses not already recovered through base rates and reconciling the prior year's over- or under-collection." Id.

As explained in the RPS docket, FERC amended its regulations in Order No. 679 to establish incentive-based (including performance-based) rate treatments for the transmission of electric energy in interstate commerce.[16] Pursuant to Order 679, FERC rules now permit various incentives for transmission investment including: (1) incentive-based Return on Equity; (2) full recovery of Construction Work in Progress and commercial expenses; (3) hypothetical capital structure; (4) accelerated depreciation; (5) full recovery of costs of abandoned facilities; (6) deferred cost recovery; and (7) single-issue ratemaking.

In addition, FERC noted that financing difficulties are a major cause of the nation's "abundant" transmission deficiencies. Those difficulties are substantially similar to the difficulties associated with AMI implementation. For example, a United States Department of Energy ("U.S. DOE") Study cited in Order 679 concluded that "[t]he Risk/Reward equation clearly does not work for investors" in the transmission infrastructure context as a result of (1) limited profit potential from a regulated investment; and (2) significant perceived investment risk associated with high up front capital costs, long and complicated regulatory processes, a large number of potential intervenors, the re-opening of entire cost-of-service rates, and long at-risk time between investments and returns.[17]

d. NARUC's AMI Resolution

In line with the EISA directive, the National Association of Regulatory Utility Commissions' ("NARUC") Committee on Energy Resources and Environment has observed that

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[16] See Final Rule Promoting Transmission Investment through Pricing Reform, Order No. 679 issued July 20, 2006 in Docket No. RM06-4-000 (18 C.F.R. Part 35), as amended by Order No. 679-A, issued December 22, 2006 in Docket No. RM06-4-001, and Order No. 679-B, issued April 19, 2007 in Docket No. RM06-4-002 ("Order 679" or the "Order").

[17] See Barriers to Transmission Investment, Presentation of Brendan Kirby, (U.S. Dept. of Energy, Oak Ridge Nat'l Lab.) April 22, 2005 Technical Conference, Transmission Independence and Investment, Docket No. AD05-5-000 (cited in Order 679, para. 10 n.8) ("DOE Study"). As a result, Order 679's reforms have been tailored to promote investments in transmission facilities by: (1) permitting higher ROEs for certain transmission investments; (2) reducing the risks of new investments; and (3) affecting the timing of recovery of new transmission investments. See Order 679, paras. 29, 48.

"[t]he deployment of cost-effective AMI technology may require the removal and disposition of existing meters that are not fully depreciated and may require replacement of, or significant modification to, existing meter reading, communications, and customer billing and information infrastructure," and that "regulated utilities may be discouraged from pursuing demand response opportunities by the prospect of diminished sales and revenues." In connection with these observations, NARUC has resolved that regulatory commissions seeking to facilitate deployment of cost-effective AMI technologies should consider the following regulatory options:

- pursue an AMI business case analysis, in conjunction with each regulated utility, in order to identify an optimal, cost-effective strategy for deployment of AMI that takes into account both tangible and intangible benefits;
- adopt ratemaking policies that provide utilities with appropriate incentives for reliance upon demand-side resources;
- provide for timely cost recovery of prudently incurred AMI expenditures, including accelerated recovery of investment in existing metering infrastructure, in order to provide cash flow to help finance new AMI deployment; and,
- provide depreciation lives for AMI that take into account the speed and nature of change in metering technology[.][18]

e. **Additional Support**

Consistent with FERC's conclusions, a recent monograph on alternate regulation prepared for the Edison Electric Institute by the Pacific Economics Group has identified accelerated cost recovery as a useful vehicle for reducing utility investment risk, stating that:

> This approach improves cash flow during construction and places fewer dollars at risk in future years, when government policies and other business conditions may have changed. Several well-established mechanisms are available to accelerate cost recovery. These include the expensing of pre-certification costs, accelerated

[18] NARUC Resolution to Remove Regulatory Barriers To the Broad Implementation of Advanced Metering Infrastructure, adopted February 21, 2007 ("NARUC Resolution") (emphasis added). The NARUC Resolution further resolved that: (1) "the Federal tax code with regard to depreciable lives for AMI investments should be amended to reflect the speed and nature of change in metering technology;" and (2) "NARUC supports movement toward an appropriate level of open architecture and interoperability of AMI to enable cost-effective investments, avoid obsolescence, and increase innovations in technology products." Id.

depreciation, the inclusion of costs of construction work in progress ("CWIP") in rate base, and formula rates.[19]

The use of alternative mechanisms to facilitate timely cost recovery has been encouraged at both national and state levels. As discussed above, EISA § 1307 amended PURPA § 111(d) by, among other things, directing states to consider "authorizing any electric utility . . . to recover in a timely manner the remaining book-value costs of any equipment rendered obsolete by the deployment of the qualified smart grid system, based on the remaining depreciable life of the obsolete equipment"[20] while EESA created a reduced depreciation period for Smart Meters and Smart Grid assets which allows taxpayers to recover the cost of smart electric meters and smart electric grud ststens iver a 10-year period while providing a positive exception for property that already qualifies for a recovery period shorter than 10 years.

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[19] Mark Newton Lowry, PhD, Alternative Regulation for Infrastructure Cost Recovery, Pacific Economics Group, January 9, 2007 at 30.

[20] Energy Independence Security Act § 1307(a), Pub. L. No. 110-140, H.R. 6 (2007).

ACCOUNTING AND RATEMAKING TREATMENT

The following exhibit details the accounting and proposed ratemaking treatment for each AMI incremental cost and incremental benefit described in Section XI of the Application.

A. INCREMENTAL AMI COST

1. New AMI Meters

New AMI meters are planned for installation at HECO beginning in 2011, at MECO beginning in 2014 and at HELCO beginning in 2015.

For book accounting purposes, the Companies will capitalize the installed costs of the new AMI meters upon installation and include the meters as utility assets. The Companies will depreciate the new AMI meters over the current Commission approved depreciation rates for meters, beginning January 1 of the following year the meters are placed into service.

For ratemaking purposes and for purposes of calculating the revenue requirements for inclusion in the REIP or AMI Surcharge (jointly referred to as the AMI Surcharge in this exhibit), the Companies propose to include the new AMI meters as utility assets in rate base and to recover the investment over a period of seven years from installation. This represents an accelerated recovery of the Companies' investment in these new AMI meters.

As previously discussed above, accelerated cost recovery mechanisms have been recognized by Congress, FERC, the U.S. DOE, NARUC, the Pacific Economics Group, state legislatures and regulatory commissions, and numerous mainland utilities, as a useful method for encouraging the development of technologies involving high up-front costs, such as AMI. The vast majority of the costs associated with the Companies' AMI project relate to the replacement of the Companies' existing meters with AMI meters, and almost all of those costs will be incurred at or near the outset of the AMI Project. Instead of carrying and recovering this investment over a longer term, to the possible detriment of the Companies' credit quality, the Companies propose to recover the investment in the meter costs by accelerating recovery through the AMI Surcharge. An accelerated cost recovery mechanism could reduce investors' perception of risk, which may help maintain the Companies' current cost of capital and mitigate a potential degradation in credit quality.

The Companies propose to recover the capital costs associated with the purchase and installation of the AMI meters by recovering the cost of those meters over a seven-year period from the time of installation, and collecting the associated incremental revenue requirement through the AMI Surcharge in a manner similar to the "adjustment clause" approaches taken by PGE and DP&L, and also under New York's AMI Plan.

The Companies' AMI Project involves new and advanced technology with capabilities that have grown rapidly in recent years. The dynamic nature of this technology serves to justify the accelerated recovery of the Companies' AMI-related capital costs. FERC noted in Order 679 that shorter depreciable lives may be appropriate for "advanced technologies for which the useful life is not necessarily known." See Order 679, para. 149. Similarly the NARUC Resolution recommends that regulatory commissions seeking to facilitate AMI implementation "provide depreciation lives for AMI that take into account the speed and nature of change in metering technology."

Recovering the investment in the new AMI meters over a seven-year period will provide improved cash flow and better position the Companies for future investments in advanced AMI-related technologies, such as demand response. Moreover, the Companies and ratepayers alike will benefit from the Companies' timely recovery of AMI meter costs, which should have a positive effect on the Companies' credit quality.

For accounting purposes, however, the depreciation of the capitalized meter costs will continue at current Commission approved depreciation rates. This, including the timing of depreciation commencement, creates a difference between cost recognition (depreciation expense) for book purposes and AMI Surcharge revenue recognition for ratemaking purposes. As the Companies propose accelerated recovery of the investment via the Commission approved AMI Surcharge for ratemaking purposes, they will receive revenues in excess of the costs recognized for book purposes. Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Certain Types of Regulation" ("SFAS No. 71), requires that if current recovery (via Commission approval of the AMI Surcharge and accounting and proposed ratemaking treatment) is provided for costs that are expected to be incurred in the future, those revenues must be recognized as a liability.[1] Therefore, for book accounting and ratemaking purposes, the Companies will record the difference in AMI Surcharge revenues received, in excess of the current depreciation expenses incurred, as a regulatory liability. Each Company will maintain and record the regulatory liability based on the AMI Surcharge revenues received and depreciation expenses recognized at the Company. The Companies also propose to include the regulatory liability balance in their rate bases, as a deduction in the calculation of rate base for ratemaking purposes. As the balance represents ratepayer provided funds, including it as a deduction in rate base is proper. Over time, the regulatory liability balance will decrease as the new AMI meters are depreciated. This regulatory liability balance will be zero when the new AMI meters are fully depreciated.

2. <u>Existing Non-AMI Meters</u>

For book accounting purposes, the Companies will continue to depreciate their existing non-AMI meters over the current Commission approved depreciation rates and to include them as

[1] SFAS No. 71, paragraph 11, b states "A regulator can provide current rates intended to recover costs that are expected to be incurred in the future with the understanding that if those costs are not incurred future rates will be reduced by corresponding amounts. If current rates are intended to recover such costs and the regulator requires the enterprise to remain accountable for any amounts charged pursuant to such rates and not yet expended for the intended purpose, the enterprise shall not recognize as revenues amounts charged pursuant to such rates. Those amounts shall be recognized as liabilities and taken to income only when the associated costs are incurred."

utility assets prior to the meters being replaced. The Companies will also retire their existing non-AMI meters as they are replaced by the new AMI meters.

For ratemaking purposes and for purposes of calculating the revenue requirements for inclusion in the AMI Surcharge, the Companies propose to accelerate the recovery of their investment in the existing non-AMI meters beginning with the receipt of the Commission Decision and Order in this docket as proposed and discussed below. The Companies' existing meter investment amount will be based on the net book value of the existing meters at the receipt of the Commission Decision and Order. The AMI Surcharge would include the net of the revenue requirements of the accelerated recovery of the existing non-AMI meters and the revenue requirements of these meters in base rates, to the extent that the retirement of these meters are not reflected in base rates.

The Companies propose to recover the cost of their existing meters (i.e., the net book value of the meters to be replaced with AMI meters) on a straight-line, accelerated basis. Once the Companies' existing meters are removed, they will no longer be "used and useful" for utility purposes. Thus, it makes sense that recovery of the costs associated with those meters should occur within a reasonable time after they are taken out of service. This treatment is consistent with the "stranded cost recovery" specified in the HCEI agreement and demonstrates support for the conversion to providing customers expanded alternatives.

This has been accomplished on the mainland by writing down the net book values of old meters on an accelerated basis. The accelerated recovery of the investment in existing meters helps other utilities finance some of the high, up-front costs associated with AMI deployment. As discussed above, this approach has been encouraged by Congress in EISA § 1307, endorsed by NARUC, and approved by the OPUC in PGE's AMI docket, in which PGE obtained approval to depreciate its existing meters over a period of two and a half years. This approach is also being pursued by other utilities such as DP&L, whose Blueprint for the Future involves accelerated recovery of existing meters over a period "not to exceed three to five years."

In line with these trends, the Companies propose to recover the remaining net book value of their existing meters and to recover the associated revenue requirement impact from customers through the REIP Surcharge or the AMI Surcharge proposed in this docket. HECO proposes to recover the remaining $13,960,000 estimated book value (as of December 31, 2009) of its existing non-AMI meters over a three-year period beginning upon receipt of the Commission Decision and Order in this docket. MECO proposes to recover the remaining $4,899,000 estimated book value (as of December 31, 2009) of its existing non-AMI meters over a period beginning upon receipt of the Commission Decision and Order in this docket and ending when MECO's meter installation begins in 2014. HELCO similarly proposes to recover the remaining $9,238,000 estimated book value (as of December 31, 2009) of its existing non-AMI meters over a period beginning upon receipt of the Commission Decision and Order and ending when HELCO's meter installation begins in 2015.

The Companies recognize that the accelerated recovery periods differ for each Company. Rather than assign three year recovery periods for all existing non-AMI meters on all islands, MECO and HELCO propose recovery over a longer period which would help smooth out the revenue requirement impact. Assigning a three-year recovery period for MECO and HELCO would possibly result in full recovery of the existing non-AMI meter investment one to two years prior to the installation of the new, advanced solid state meters on these islands. Since installation of the new AMI meters on Maui and Hawaii is scheduled for 2014 and 2015, respectively, there could possibly be a decrease in the revenue requirement impact in the years prior to new meter installation, but after the existing non-AMI meter costs have already been recovered. However, there would be a significant increase when the new meter installation begins on these islands and MECO and HELCO begin recovering these investments. This would create erratic movement in the AMI Surcharge due to the increases and decreases in the revenue requirement. Therefore, MECO and HELCO's proposed accelerated recovery period for the existing non-AMI meters should help smooth out the revenue requirement and lessen the impact to ratepayers.

However, as discussed for the new AMI meters, the difference in book accounting treatment and ratemaking treatment of the existing non-AMI meters would create a difference between cost recognition and AMI Surcharge revenue recognition. For book accounting purposes, the existing non-AMI meter costs would continue to be included as utility assets and depreciated at current Commission approved depreciation rates until they are replaced. However, the proposed straight-line, accelerated recovery of these existing non-AMI meters via the AMI surcharge would result in the receipt of revenues in excess of the book depreciation costs recognized in these years and in advance of the ultimate replacement of these meters. For example, as proposed for HELCO, assuming a Decision and Order is received in 2010, the existing non-AMI meters would be recovered on an accelerated basis between 2010 through 2014. Thus, HELCO would recover its investment in these existing meters prior to when they are to be replaced in 2015 and in excess of the book depreciation. Therefore, for book accounting and ratemaking purposes, the Companies will record the difference in AMI Surcharge revenues received, in excess of the current depreciation expenses incurred and in advance of the meters retired, as a regulatory liability. The regulatory liability balance represents the excess of AMI Surcharge revenues received from ratepayers, in excess of the depreciation expense recognized by the Companies and in advance of these meters being retired upon being replaced. The Companies will each maintain and record the regulatory liability based on the activity at each respective Company. The Companies also propose to include the regulatory liability balance as a deduction in the calculation of rate base for ratemaking purposes. As the balance represents ratepayer provided funds, including it as a deduction in rate base is proper. The regulatory liability balance will decrease as the existing non-AMI meters are depreciated and replaced. The regulatory liability balance will be zero upon the completion of the meter installation and when all the replaced meters are retired.

3. <u>MDMS Capital Costs, Deferred Software Development Costs and Expenses</u>

This section discusses the purchase and installation costs for hardware related to the MDMS, deferred software development costs beginning in 2010 and related expenses.

a. <u>Capital Costs</u>

For book accounting purposes, the Companies will capitalize the installed costs of the MDMS hardware and include as utility assets. The Companies will depreciate the MDMS hardware over the current Commission approved depreciation rates, beginning January 1 of the following year the hardware is placed into service.

For ratemaking purposes and for purposes of calculating the revenue requirements for inclusion in the AMI Surcharge, the Companies propose to recover the investment by including the MDMS hardware as utility assets in rate base and recovering its investment over the current Commission approved depreciation rates. The estimated revenue requirements would be recovered through the AMI Surcharge.

b. <u>Deferral and Amortization of MDMS Software Development Costs</u>

The MDMS costs will be allocated among each of the Companies based on the customer counts as discussed in Section X of the Application. The MDMS will have many features and capabilities with installation planned in three phases. In phase I, the basic capabilities of the MDMS will be designed, coded and installed. Phase I is expected to be operational and ready for its intended use in late 2010 or early 2011. Work on phase II will follow immediately after phase I and include certain advanced capabilities. This phase is expected to be operational and ready for its intended use in late 2011. Work on phase III will begin immediately after phase II and include final customization. This phase is expected to be operational and ready for its intended use in late 2012. See Exhibit 8 for further discussion of the MDMS software and Section X of the Application for a more detailed cost estimate and breakdown.

The Companies propose to account for the development of the MDMS software in accordance with Emerging Issues Task Force Bulletin 97-13 ("EITF 97-13"), Accounting for Costs Incurred in Connection with a consulting Contract or an Internal Project that Combines Business Process Reengineering and Information Technology Transformation, and FASB Statement of Position 98-1 ("SOP 98-1"), Accounting for the Costs of Computer Software Developed or Obtained for Internal Use as the Commission has approved for other software development projects. Under the Companies' proposal, software development costs incurred during the preliminary stage (i.e., conceptual formation of software alternatives, determination of the existence of needed technology, and final selection of alternatives) and post-implementation/operation (i.e., training and application maintenance) of the AMI Project will be expensed as incurred. In the interim, during the application development stage of the AMI Project, the Companies request approval to: (1) defer (i.e., capitalize) certain computer software development costs associated with the MDMS, excluding those costs that should be expensed as incurred such as conversion costs, training, certain overhead costs and EITF 97-13-type costs, if any; (2) accumulate AFUDC on the deferred costs during the deferral period; (3) amortize the deferred costs over a 12-year period; and (4) include the unamortized costs in rate base.

The application and development stage typically includes the design of a chosen path, including software configuration, and software interface, coding, software installation and testing, including parallel processing. Costs that should be deferred during this stage include costs to develop or obtain software that allows for access of old data by new systems, and applicable overhead and AFUDC costs on the deferrable costs.[2]

The Companies requested treatment is substantially similar to the financial accounting and ratemaking treatments approved for the OMS, CIS and HRMS project costs as proposed, the treatments were intended to be consistent with the accounting guidelines of SOP 98-1. For example, under the OMS/CIS[3] proposals:

1. Project costs would be either expensed or capitalized (i.e., deferred) depending on the stage in which the costs are incurred, including (a) Stage 1 – Preliminary, (b) Stage 2 – Application Development and (c) Stage 3 – Post Implementation/Operation;

2. AFUDC would be applied to the deferred project costs during Stage 2;

3. The deferred costs would be amortized over a ten-year period (or such other amortization period as the PUC finds to be reasonable), to the appropriate operating and maintenance expense account(s), based on the benefiting organization. The amortization period would commence the month after Stage 2 is completed;

4. Unamortized deferred costs would be included in the calculation of rate base; and

5. The accounting treatment for capital costs (e.g., hardware costs) would follow existing practices.

In subsequent settlement agreements with the Consumer Advocate, the parties agreed that the accounting treatment of the OMS/CIS project would be in conformance with generally accepted accounting principles ("GAAP"), including EITF 97-13, and SOP 98-1. With respect to the CIS project, the parties stipulated that:

(a) Accordingly, the Companies agree to work with the Consumer Advocate to identify costs related to process reengineering after the gap analysis between the CIS software package and the current customer billing process is completed. The

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[2] Although data conversion often occurs during the application development stage, the Companies do not seek to defer data conversion costs other than the costs to develop or obtain software that allows for access of old data by new systems.

[3] OMS: Docket No. 04-0131. CIS: Docket No. 04-0268. HRMS: Docket No. 2006-0003.

significance of identifying reengineering costs incurred as a result of the new CIS is that these costs would be expensed.

(b) Certain overhead costs, currently estimated at approximately $211,000, relating to customer installations and corporate administration are currently included in the deferred costs as the current Ellipse system includes such costs as part of the normal overhead calculation process. The Parties agree that overhead costs should be expensed in accordance with SOP 98-1, and the Companies will identify and track the overhead costs and reclassify the costs each month, as appropriate.

In addition, although the Companies estimated that the expected useful life of the CIS project would be 10 years, they agreed to amortize the project over a 12-year period.[4] The Companies also agreed to a 12-year amortization period for the HR Suite[5] and OMS[6] projects. Therefore, the Companies propose that any deferred AMI Project MDMS software development costs also be amortized over 12 years.

For book accounting purposes, if the proposed ratemaking treatment is allowed, the Companies will defer the software development costs (and related AFUDC) of MDMS and amortize them over a 12-year period. (Absent approval to defer these costs, the Companies will have to record the costs as expenses when incurred.) For ratemaking purposes and for purposes of calculating the revenue requirements for inclusion in the AMI Surcharge, the Companies propose to defer and amortize the software development costs of MDMS over a 12-year period and to include the unamortized balance in rate base.

As the MDMS software will be developed and implemented in three separate phases, the Companies propose to amortize the deferred software development costs in each phase separately over a 12-year amortization period. In each phase, as previously described, certain functionalities and features will be designed, coded and installed. The functionalities and features will be installed and ready for use at three different times (at the end of each phase). Therefore, the Companies

[4] Decision and Order No. 21798 in Docket No. 04-0268, issued May 3, 2005.
[5] Decision and Order No. 23413 in Docket No. 2006-003, issued May 3, 2007.
[6] Decision and Order No. 21899 in Docket No. 04-0131, issued June 30, 2005.

propose to track and defer the costs incurred in each phase separately and to begin amortization in the month after the functionalities installed in that particular phase are deemed operational and ready for their intended use. The costs deferred specific to each individual phase will be amortized over 12 years.

c. MDMS-Related Expenses

For book accounting purposes, the Companies will record and recognize MDMS-related expenses (e.g., training, process and change management, support and maintenance) as they are incurred. For ratemaking purposes, the Companies propose to include the MDMS-related expenses for purposes of calculating the revenue requirements for inclusion in the AMI Surcharge.

However, as discussed earlier regarding the AMI Surcharge, it is proposed that the Companies will recover forecast expenses. Therefore, there may potentially be differences in the timing of the incurrence of these expenses and the recovery via the AMI Surcharge. In addition, there will potentially be differences in the amounts recovered via the AMI Surcharge and the amounts actually incurred in that period. Thus, if the proposed ratemaking treatment is approved, the Companies will record the portion of the AMI Surcharge revenues in excess of the MDMS-related expenses recognized for book purposes as a regulatory liability. For book purposes, the revenues would be recognized upon recognition of the MDMS-related expenses. For ratemaking purposes, the regulatory liability balance (or regulatory asset balance if MDMS-related expenses incurred exceed the forecasted expenses recovered via the AMI Surcharge) will accrue interest with the differences reconciled and adjusted in the following period's surcharge.

4. AMI Network Capital Costs, Lease Expense and Other Expenses

This section discusses the purchase and installation costs for hardware related to the AMI Network (FNP/FRP) discussed in Section VII.C of the Application, as well as expenses related to the use of the Sensus owned, operated and maintained AMI Network.

a. Capital Costs

For book accounting purposes, the Companies will capitalize the installed costs of the FNP/FRP hardware and include as utility assets. The Companies will depreciate the FNP/FRP hardware over the current Commission approved depreciation rates, beginning January 1 of the following year the hardware is placed into service.

For ratemaking purposes and for purposes of calculating the revenue requirements for inclusion in the AMI Surcharge, the Companies propose to recover the investment by including the FNP/FRP hardware as utility assets in rate base and recovering the investment over the current Commission approved depreciation rates. The estimated revenue requirements would be recovered through the AMI Surcharge.

b. Lease Agreement

The Companies' AMI proposal involves the use of a Sensus owned, operated and maintained AMI Network in exchange for a monthly, per-meter fee, to be imposed upon the deployment of each respective meter, in accordance to the provisions of the Sensus Agreement.

The Company has completed an evaluation of the Sensus agreement under Emerging Issues Task Force ("EITF") Issue No. 01-8 entitled "Determining Whether an Arrangement Contains a Lease"[7] and determined that the Sensus Agreement contains a lease. Further, the Company determined that under Statement of Financial Accounting Standards ("SFAS") No. 13, "Accounting for Leases," the lease is an operating lease.

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[7] See further explanation of EITF 01-8 in "Lease Arrangements Have Broadened" filed in Docket No. 04-0113 HECO's 2005 test year rate case, HECO-2113.

Under SFAS No. 13, lease payments over the fixed term of the lease must be recorded on a straight-line basis over the fixed term of the lease, even if the payments are not made on a straight-line basis. The lease payments to Sensus are to be based on a monthly per endpoint fee times the number of meters installed, to be paid beginning upon installation of the meters. The monthly per endpoint fee is to escalate over time as described in the Sensus agreement which would escalate the annual lease payments made to Sensus. Therefore, in accordance with SFAS No. 13, the Companies must recognize expenses related to the lease on a straight-line basis over the 15 year term beginning with the effective date of the lease (i.e. at Commission approval). As a result, expense recognition is greater than the lease payments in the early years of the term of the lease. As the 15-year term of the agreement begins prior to actual meter installation, straight-line lease expense will be recorded in advance of payments actually being made in the early years of the lease term. After meter installation begins, the straight-line lease expense recorded will initially be higher than the actual lease payments made. However, in the later years of the agreement this will reverse and the straight-line lease expense recorded will be lower than the lease payments made.

The Companies propose that ratemaking be based on the lease payments as they are paid over the term of the lease. The HECO Companies respectfully request Commission assurances that rate recovery of the AMI Network will be based on lease payments over the 15-year term of the agreement. Commission assurance that future ratemaking will be based on the lease payments will allow the Companies to record a regulatory asset for the difference between the straight-line expense required under GAAP and the lease payments made under the agreement. In the early years of the 15-year lease term the regulatory asset balance will grow as the straight-line lease expenses will be in excess of actual lease payments made. As the lease agreement progresses through the 15-year term, the actual lease payments made will be higher than the straight-line lease expense. This difference will reduce the regulatory asset balance until eventually the regulatory asset balance will be zero by the end of the fixed lease term. This treatment will allow for a matching of the revenues received and the book recognition of lease expense, resulting in no earnings impact. This regulatory asset would not be included in rate base as it does not represent investor provided funds.

c. <u>Impact of Imputed Debt on Credit Quality</u>

The credit rating agencies have determined that certain obligations of a Company that are not reported as liabilities on the Companies' balance sheet should be reflected as debt in the ratios used to evaluate the Companies' risk profile. In order to capture the risks associated with these obligations, the credit rating agencies calculate "imputed debt." In the Companies' case, the credit rating agencies impute debt for its long-term operating lease obligations.

The Companies prepared estimates of the imputed debt and rebalancing costs based on S&P's methodology and included such estimates in the revenue requirement calculation as discussed in Exhibit 22 . Imputed debt in the year lease payments begin are estimated to be $7,800,000 at HECO in 2011, $1,700,000 at MECO in 2014 and $2,300,000 at HELCO at 2015. The annual rebalancing costs are estimated at about $642,000 at HECO, $142,000 at MECO and $189,000 at HELCO. The amount of imputed debt and related rebalancing costs will decline over the term of the agreement.

For ratemaking purposes, the Companies propose to include the lease expense in revenue requirements for inclusion in the AMI Surcharge, but to exclude the imputed debt and annual rebalancing costs for purposes of calculating the AMI Surcharge revenue requirements. This is illustrated in Exhibit 22.

It is proposed that the Companies recover forecast expenses. There may potentially be differences in the amounts recovered via the AMI Surcharge and the actual lease payments made in that period. To the extent the Companies receive AMI Surcharge revenues in excess of the straight-line lease expenses recorded, the difference will be recorded as a regulatory liability. A regulatory asset would be recorded if the straight-line lease expense recorded exceeds the recovery of the forecasted lease expense received via the AMI surcharge. The regulatory liability balance (or regulatory asset balance) will accrue interest with the differences reconciled and adjusted in the following period's surcharge.

d. <u>AMI Network Related Expenses</u>

For book accounting purposes, the Companies will record and recognize AMI Network related expenses as they are incurred. For ratemaking purposes, the Companies propose to include the AMI Network related expenses in the revenue requirements for inclusion in the AMI Surcharge.

As discussed earlier regarding the AMI Surcharge, it is proposed that the Companies recover forecast expenses. Therefore, there may potentially be differences in the timing of the incurrence of these expenses and the recovery via the AMI Surcharge. In addition, there will potentially be differences in the amounts recovered via the AMI Surcharge and the amounts actually incurred in that period. The Companies will record any AMI Surcharge revenues in excess of its related AMI Network related expenses as a regulatory liability. The revenues would be recognized upon incurrence of the AMI Network related expenses. The regulatory liability balance (or regulatory asset balance if AMI Network related expenses incurred exceed the forecasted expenses recovered via the AMI Surcharge) will accrue interest with the differences reconciled and adjusted in the following period's surcharge.

5. <u>Other AMI Project Expenses</u>

The Companies expect to incur other costs while developing and implementing the AMI Project. These costs include: (1) damaged meter socket costs, and (2) outside services consulting costs.

a. <u>Damaged Meter Socket Costs</u>

The Companies expect to have to replace damaged meter sockets when installing the new AMI meters. It is expected that some meter sockets may be damaged when the existing non-AMI meters are removed or it will be find that some meter sockets may already be damaged or in need of replacement.

For book accounting purposes, the Companies will record and recognize damaged meter socket related expenses as they are incurred. For ratemaking purposes, the Companies propose to include the damaged meter socket related expenses for purposes of calculating the revenue requirements for inclusion in the AMI Surcharge.

However, as discussed earlier regarding the AMI Surcharge, it is proposed that the Companies recover forecast expenses. Therefore, there may potentially be differences in the timing of the incurrence of these expenses and the recovery via the AMI Surcharge. In addition, there will potentially be differences in the amounts recovered via the AMI Surcharge and the amounts actually incurred in that period. Thus, if the proposed ratemaking treatment is approved, the Companies will record the portion of the AMI Surcharge revenues in excess of the damaged meter socket related expenses recognized for book purposes as a regulatory liability. For book purposes, the revenues would be recognized upon recognition of the damaged meter socket related expenses. For ratemaking purposes, the regulatory liability balance (or regulatory asset balance if damaged meter socket related expenses incurred exceed the forecasted expenses recovered via the AMI Surcharge) will accrue interest with the differences reconciled and adjusted in the following period's surcharge.

b. <u>Outside Consulting Costs</u>

The Companies expect to retain outside consultants to assist with certain aspects of the AMI Project.

For book accounting purposes, the Companies will record and recognize the outside consulting expenses as they are incurred. For ratemaking purposes, the Companies propose to include the outside consultant costs in the revenue requirements for inclusion in the AMI Surcharge. Any incremental labor costs for those employees working on the AMI Project will be reflected in the AMI surcharge to the extent that they are not reflected in base rates.

As discussed earlier regarding the AMI Surcharge, it is proposed that the Companies will recover forecast expenses. Therefore, there may potentially be differences in the timing of the incurrence of these expenses and the recovery via the AMI Surcharge. In addition, there will potentially be differences in the amounts recovered via the AMI Surcharge and the amounts actually incurred in that period. The Companies will record any AMI Surcharge revenues in excess of their related other AMI project expenses as a regulatory liability. The revenues would be recognized upon incurrence of these other AMI project expenses. The regulatory liability balance (or regulatory asset balance if these other AMI project expenses incurred exceed the forecasted expenses recovered via the AMI Surcharge) will accrue interest with the differences reconciled and adjusted in the following period's surcharge.

B. <u>OFFSETTING INCREMENTAL AMI BENEFIT</u>

As indicated in Section XI of the Application, the Companies are not proposing to collect all of the AMI Project's costs through a surcharge. The Companies only propose to flow the project's incremental revenue requirements through the surcharge to the extent that the incremental revenue requirements are not captured in base rates or any other surcharge mechanism. Thus, the AMI Project costs recovered though the surcharge will be net of the incremental quantifiable benefits created by the AMI Project that are not captured in base rates or any other surcharge mechanism. The quantifiable benefits of the AMI Project include:

- utility expense savings resulting from elimination of manual meter reads,
- field services savings related to remote disconnect/reconnect and remote read capabilities,
- ratepayer revenue enhancements resulting from energy theft recovery, and
- ratepayer revenue enhancements resulting from meter accuracy gains.

These benefits were quantified in Section X of the Application.

Proposal for Time-of-Use Rate Options

Current Status of Time-of-Use Rate Options

Time-of-use rate options for all customers are available at HECO as approved in HECO's 2005 test year rate case. Similar time-of-use rate options for all customers are proposed in the currently open HELCO 2006 test year rate case and MECO 2007 test year rate case.

Residential Time-of-Use Rate Option Proposal

The rate design of Schedule TOU-R for residential customers proposed in the HECO 2009 test year rate case (which includes only two time-of-use rate periods and a five hour daily on-peak period) represents the HECO Companies' current assessment of the appropriate rate design form. That form is proposed for the time-of-use rate option for residential customers at HECO, HELCO, and MECO in this application, based on the costs in the most recent rate case applications for each Company (HECO 2009 test year, HELCO 2006 test year, MECO 2007 test year), as shown below. HELCO and MECO will also propose this rate form as the Schedule TOU-R rate option for residential customers in their respective expected 2009 test year rate cases. The HECO Companies also request that the proposed time-of-use rate options for residential customers in this application, if approved, remain in place and supersede the residential time-of-use rate proposals in the open rate cases for HELCO's 2006 test year, HECO's 2007 test year, and MECO's 2007 test year, where the Schedule TOU-R rate option for residential customers proposes three time-of-use rate periods, if those proposed time-of-use rates are approved by the Commission. The Schedule TOU-R rates proposed in the open rate cases do not impact the revenue requirements in those rate cases, and likewise, adjusting the proposed rate form will not impact those rate case revenue requirements.

Commercial Time-of-Use Rate Option Proposal

In this application, HELCO and MECO request that the Commission approve time-of-use rate options proposed for commercial customers (Schedule TOU-G, Small Commercial Time-Of-Use Service; Schedule TOU-J, Commercial Time-of- Use Service; and Schedule TOU-P, Large Power Time-of-Use Service), as shown below. These proposed commercial time-of-use rate options are based on the rate option forms proposed in the HELCO 2006 test year rate case and MECO 2007 test year rate case, respectively, and the rate levels are based on the settlement agreements achieved in those rate cases. HELCO and MECO also request that the proposed time-of-use rate options for commercial customers in this application remain in place and supersede the commercial time-of-use rate proposals in the open rate cases for HELCO's 2006 test year and MECO's 2007 test year, where Schedule TOU-G, Schedule TOU-J, and Schedule TOU-P rate options for commercial customers are proposed, if those proposed time-of-use rates are approved by the Commission. The commercial time-of-use rate options proposed in the open rate cases do not impact the revenue requirements in those rate cases, and likewise, revising the proposed rate options will not impact those rate case revenue requirements.

Alignment of Energy Cost Adjustment Clause Rates

For all residential and commercial time-of-use rate options proposed in this application, the HECO Companies have adjusted the proposed rate levels to be consistent with the current energy cost adjustment clause at each utility. HECO, HELCO, and MECO will submit revised time-of-use rate option proposals for residential and commercial customers to re-price the rates to be consistent relative to the regular rate schedule rates and the energy cost adjustment clauses that the Commission approves in final decisions in the open rate cases for the HELCO 2006 test year, HECO 2007 test year, MECO 2007 test year, and HECO 2009 test year.

Limitations on Participation in Time-of-Use Rate Options

In the existing HECO time-of-use rate options as well as in the proposed time-of-use rate options in the HELCO 2006 test year, HECO 2007 test year, MECO 2007 test year, and HECO 2009 test year rate cases, there are explicit customer limits for participation in time-of-use rate options until the new billing system (CIS – Customer Information System) is in place. These limits are proposed in order to manage the HECO Companies ability to deliver timely bills for time-of-use rate option customers since all of those bills must be calculated and processed manually. The time-of-use rate options proposed in this application remove those meter limits previously proposed. The HECO Companies will make their best efforts to accommodate all customers who wish to participate in these time-of-use rate options. However, the HECO Companies also propose to reserve the right to apply to the Commission for meter limitations if and when the HECO Companies become unable to calculate and deliver bills in a timely manner to customers on residential and commercial time-of-use rate options.

SCHEDULE TOU-R

RESIDENTIAL TIME-OF-USE SERVICE

AVAILABILITY:

Applicable to residential power service metered and billed separately by the Company. This Schedule does not apply where a residence and business are combined. Service under this Schedule will be delivered at secondary voltage specified by the Company.

RATES:

CUSTOMER CHARGE - $ per customer per month:

Single-Phase Service - per month	$10.50/month
Three-Phase Service - per month	$18.50/month

ENERGY CHARGES - ¢ per kWhr:

TIME-OF-USE CHARGES - ¢ per kWhr:

On-Peak Period - per kWhr	35.9903 ¢/kWhr
Off-Peak Period - per kWhr	14.9903 ¢/kWhr

USAGE CHARGES - ¢ per kWhr:

All kWhr between 350 - 1,200 kWhr per month-	1.0 ¢/kWhr
All kWhr over 1,200 kWhr per month-	2.0 ¢/kWhr

MINIMUM CHARGE:

Single-Phase Service - per month	$18.50/month
Three-Phase Service - per month	$23.50/month

SCHEDULE TOU-R - (continued)

TIME-OF-USE RATING PERIODS:

The time-of-use rating periods under this Schedule shall be defined as follows:

On-Peak:	3:00 p.m. - 8:00 p.m., daily
Off-Peak:	8:00 p.m. - 3:00 p.m., daily

DETERMINATION OF TIME-OF-USE ENERGY:

The Company shall install, own, operate and maintain a time-of-use meter to measure the customer's kWhr energy consumption during the time-of-use rating periods.

TERMS AND CONDITIONS:

1. The Company may meter the customer's energy usage pattern for one to three months before the customer's service start date under this Schedule, to allow the Company to gather the customer's baseline load profile.

2. The Company shall install the time-of-use meter in accordance with Rule 14. Although the existing service equipment is expected to be used, the customer shall provide, install, and maintain the service equipment specified in Rule 14, such as all the conductors, service switches, meter socket, meter panel, and other similar devices required for service connection and meter installations on the customer's premises.

3. The Company may request a customer to allow the Company shared-use of its telephone line to enable the Company to remotely download the customer's usage data from the meter.

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Schedule TOU-R - (continued)

TERMS AND CONDITIONS - continued:

4. A customer may terminate service under this rate Schedule and return to the regular Schedule R at any time without penalty, by a written notice to the Company. The change shall become effective at the start of the next regular billing period following the date of receipt by the Company of the notice from the customer. If a customer elects to discontinue service under this Schedule, the customer will not be permitted to return to this Schedule for a period of one year.

ENERGY COST ADJUSTMENT CLAUSE:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer and Energy Charges.

INTEGRATED RESOURCE PLANNING COST RECOVERY PROVISION:

The Integrated Resource Planning Surcharge shall be added to the Customer and Energy Charges, and energy cost adjustment.

RULES AND REGULATIONS:

Service supplied under this rate schedule shall be subject to the Rules and Regulations of the Company.

SCHEDULE TOU-R

RESIDENTIAL TIME-OF-USE SERVICE

AVAILABILITY:

Applicable to residential service metered and billed separately by the Company. This Schedule does not apply where a residence and business are combined. Service under this Schedule will be delivered at secondary voltages as specified by the Company.

RATES:

CUSTOMER CHARGE - $ per customer per month:

Single-Phase Service - per month	$11.00/month
Three-Phase Service - per month	$15.50/month

ENERGY CHARGES - ¢ per kWhr:

<u>Time-of-Use Charges - ¢ per kWhr</u>

On-Peak Period - per kWhr	37.1267 ¢/kWhr
Off-Peak Period - per kWhr	16.1267 ¢/kWhr

<u>Usage Charges - ¢ per kWhr</u>

All kWhr between 300 - 1,000 kWhr per month	2.0 ¢/kWhr
All kWhr over 1,000 kWhr per month-	3.0 ¢/kWhr

MINIMUM CHARGE:

The minimum charge shall be $20.00.

SCHEDULE TOU-R - (continued)

TIME-OF-USE RATING PERIODS:

The time-of-use rating periods under this Schedule shall be defined as follows:

On-Peak:	3:00 p.m.-8:00 p.m., daily
Off-Peak:	8:00 p.m.-3:00 p.m., daily

DETERMINATION OF TIME-OF-USE ENERGY:

The Company shall install, own, operate and maintain a time-of-use meter to measure the customer's kWhr energy consumption during the time-of-use rating periods.

TERMS AND CONDITIONS:

1) The Company may meter the customer's energy usage pattern for one to two months before the customer's service start date under this Schedule, to allow the Company to gather the customer's baseline load profile.
2) The Company shall install the time-of-use meter in accordance with Rule 14. Although the existing service equipment is expected to be used, the customer shall provide, install, and maintain the service equipment specified in Rule 14, such as all the conductors, service switches, meter socket, meter panel, and other similar devices required for service connection and meter installations on the customer's premises.
3) The Company may request a customer to allow the Company shared-use of its telephone line to enable the Company to remotely download the customer's usage data from the meter.

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Schedule TOU-R - (continued)

TERMS AND CONDITIONS - continued:

4) A customer may terminate service under this rate Schedule and return to the regular Schedule R at any time without penalty, by a written notice to the Company. The change shall become effective at the start of the next regular billing period following the date of receipt by the Company of the notice from the customer. If a customer elects to discontinue service under this Schedule, the customer will not be permitted to return to this Schedule for a period of one year.

ENERGY COST ADJUSTMENT CLAUSE:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer and Energy Charges.

INTEGRATED RESOURCE PLANNING COST RECOVERY PROVISION:

The Integrated Resource Planning Surcharge shall be added to the Customer and Energy Charges, and energy cost adjustment.

RULES AND REGULATIONS:

Service supplied under this rate schedule shall be subject to the Rules and Regulations of the Company.

SCHEDULE TOU-G

SMALL COMMERCIAL TIME-OF-USE SERVICE

AVAILABILITY:

Applicable to general light and/or power loads less than or equal to 5,000 kilowatthours per month, and less than or equal to 25 kilowatts, and supplied through a single meter. Customers served under this Schedule who exceed 5,000 kilowatthours per month or 25 kilowatts will be automatically transferred to Schedule TOU-J at the beginning of the next billing period.

Service will be delivered at secondary voltages as specified by the Company, except where the nature or location of the customer's load makes delivery at secondary voltage impractical, the Company may, at its option, deliver the service at a nominal primary voltage as specified by the Company.

RATE:

CUSTOMER CHARGE:

Single-Phase Service - per month	\$34.00/month
Three-Phase Service - per month	\$56.00/month

ENERGY CHARGE: (To be added to Customer Charge)

Priority Peak Period - per kWhr	28.6941 ¢/kWhr
Mid-Peak Period - per kWhr	26.1941 ¢/kWhr
Off-Peak Period - per kWhr	18.2941 ¢/kWhr

MINIMUM CHARGE: Customer Charge

SCHEDULE TOU-G - continued

TIME-OF-USE RATING PERIODS:

The time-of-use rating periods shall be as follows:

Priority Peak:	5:00 p.m. - 9:00 p.m.,	Monday - Friday
Mid-Peak:	7:00 a.m. - 5:00 p.m.,	Monday - Friday
	7:00 a.m. - 9:00 p.m.,	Saturday - Sunday
Off-Peak:	9:00 p.m. - 7:00 a.m.,	Daily

DETERMINATION OF TIME-OF-USE ENERGY:

The Company shall install, own, operate and maintain a time-of-use meter to measure the customer's kWhr energy consumption during the time-of-use rating periods.

TERMS AND CONDITIONS:

1) The Company may meter the customer's energy usage pattern for one to two months before the customer's service start date under this Schedule, to allow the Company to gather the customer's baseline load profile.

2) The Company shall install the time-of-use meter in accordance with Rule 14. Although the existing service equipment is expected to be used, the customer shall provide, install, and maintain the service equipment specified in Rule 14, such as all the conductors, service switches, meter socket, meter panel, and other similar devices required for service connection and meter installations on the customer's premises.

SCHEDULE TOU-G - continued

TERMS AND CONDITIONS - continued:

3) The Company may request a customer to allow the Company shared-use of its telephone line to enable the Company to remotely download the customer's usage data from the meter.

4) A customer may terminate service under this rate Schedule and return to the regular Schedule G at any time without penalty, by a written notice to the Company. The change shall become effective at the start of the next regular billing period following the date of receipt by the Company of the notice from the customer. If a customer elects to discontinue service under this Schedule, the customer will not be permitted to return to this Schedule for a period of one year.

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer, Demand, and Energy charges.

Integrated Resource Planning Cost Recovery Provision:

The Integrated Resource Planning Surcharge shall be added to the Customer, Demand, and Energy charges, and energy cost adjustment.

Rules and Regulations:

Service supplied under this rate shall be subject to the Rules and Regulations of the Company.

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SCHEDULE TOU-J

COMMERCIAL TIME-OF-USE SERVICE

AVAILABILITY:

Applicable to general light and/or power loads which exceed 5,000 kilowatthours per month three times within a twelve-month period or which exceed 25 kW per month and but are less than 300 kW per month. This Schedule cannot be used in conjunction with load management Riders M, T, and I, Schedule U, and Schedule TOU-P.

RATE:

CUSTOMER CHARGE:

Single-Phase Service - per month	$46.00/month
Three-Phase Service - per month	$71.00/month

DEMAND CHARGE - (To be added to Customer and Energy Charge)

Priority Peak	- per kW of billing demand	$18.95/kW
Mid-Peak	- per kW of billing demand	$9.00/kW.

The customer shall be billed the Priority Peak demand charge if his maximum measured kW demand for the billing period occurs during the priority peak period. If the customer's maximum measured kW demand for the billing period occurs during the Mid-Peak period, the Mid-Peak demand charge will apply. If the customer's maximum kW demand during the Priority Peak period is equal to his maximum kW demand during the Mid-Peak period, the Priority Peak demand charge shall apply.

ENERGY CHARGE: (To be added to Customer Charge)

Priority Peak Period	- per kWhr	24.0533 ¢/kWhr
Mid-Peak Period	- per kWhr	22.0533 ¢/kWhr
Off-Peak Period	- per kWhr	12.0533 ¢/kWhr

SCHEDULE TOU-J - (continued)

MINIMUM CHARGE:

The minimum charge per month shall be the sum of the Customer Charge and the Demand Charge. The Demand Charge shall be computed with the above demand charge applied to kilowatts of demand. The kilowatts of demand for the minimum charge calculation each month shall not be less than 25 kW

TIME-OF-USE RATING PERIODS:

The time-of-use rating periods shall be as follows:

Priority Peak:	5:00 p.m. - 9:00 p.m., Monday - Friday
Mid-Peak:	7:00 a.m. - 5:00 p.m., Monday - Friday
	7:00 a.m. - 9:00 p.m., Saturday - Sunday
Off-Peak:	9:00 p.m. - 7:00 a.m., Daily

DETERMINATION OF TIME-OF-USE ENERGY AND DEMAND:

The Company shall install a time-of-use meter to measure the customer's kilowatthour consumption and kilowatt load during the time-of-use rating periods. The maximum demand for the rating periods for each month shall be the maximum average load in kilowatts during any fifteen-minute period as indicated by a time-of-use meter. The kilowatts of billing demand for each month shall be the maximum measured demand outside of the Off-Peak hours, but not less than 25 kW.

Power Factor:

The above energy and demand charges are based upon an average monthly power factor of 85%. For each 1% the average power factor is above or below 85%, the monthly energy and demand charges as computed under the above rates shall be decreased or increased, respectively, by 0.10%

SCHEDULE TOU-J - (continued)

Power Factor - continued:

The average monthly power factor will be determined from the readings of a kWhr meter and kvarh meter, and will be computed to the nearest whole percent and not exceeding 100% for the purpose of computing the adjustment. The kvarh meter shall be ratcheted to prevent reversal in the event the power factor is leading at any time.

Supply Voltage Delivery:

If the customer takes delivery at the Company's supply line voltage, the demand and energy charges will be decreased as follows:

Transmission voltage supplied without further transformation -4.0%
Distribution voltage supplied without further transformation -2.5%

Metering will normally be at the delivery voltage. When the customer's transformers are adjacent to the delivery point, the customer may elect to be metered at a single point on the secondary side of his transformers where such point is approved by the Company. When the energy is metered on the secondary side of the customer's transformers, the above decreases will be 3.1% and 0.6%, respectively.

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer, Demand, and Energy charges.

Integrated Resource Planning Cost Recovery Provision:

The Integrated Resource Planning Surcharge shall be added to the Customer, Demand, and Energy charges, and energy cost adjustment.

Rules and Regulations:

Service supplied under this rate shall be subject to the Rules and Regulations of the Company.

SCHEDULE TOU-P

LARGE POWER TIME-OF-USE SERVICE

AVAILABILITY:

Applicable to large light and/or power service supplied and metered at a single voltage and delivery point. Loads must exceed 200 kW per month. This Schedule cannot be used in conjunction with load management Riders M, T, and I, and Schedule TOU-P.

RATE:

CUSTOMER CHARGE: $410.00 per month

DEMAND CHARGE - (To be added to Customer and Energy Charge)

Priority Peak	- per kW of billing demand	$23.25/kW
Mid-Peak	- per kW of billing demand	$18.25/kW.

The customer shall be billed the Priority Peak demand charge if his maximum measured kW demand for the billing period occurs during the priority peak period. If the customer's maximum measured kW demand for the billing period occurs during the Mid-Peak period, the Mid-Peak demand charge will apply. If the customer's maximum kW demand during the Priority Peak period is equal to his maximum kW demand during the Mid-Peak period, the Priority Peak demand charge shall apply.

ENERGY CHARGE: (To be added to Customer Charge)

Priority Peak Period	- per kWhr	20.6509 ¢/kWhr
Mid-Peak Period	- per kWhr	18.6509 ¢/kWhr
Off-Peak Period	- per kWhr	8.6509 ¢/kWhr

SCHEDULE TOU-P - (continued)

MINIMUM CHARGE:

The minimum charge per month shall be the sum of the Customer Charge and the Demand Charge. The Demand Charge shall be computed with the above demand charge applied to kilowatts of demand. The kilowatts of demand for the minimum charge calculation each month shall not be less than 200 kW

TIME-OF-USE RATING PERIODS:

The time-of-use rating periods shall be as follows:

Priority Peak:	5:00 p.m. - 9:00 p.m.,	Monday - Friday
Mid-Peak:	7:00 a.m. - 5:00 p.m.,	Monday - Friday
	7:00 a.m. - 9:00 p.m.,	Saturday - Sunday
Off-Peak:	9:00 p.m. - 7:00 a.m.,	Daily

DETERMINATION OF TIME-OF-USE ENERGY AND DEMAND:

The Company shall install a time-of-use meter to measure the customer's kilowatthour consumption and kilowatt load during the time-of-use rating periods. The maximum demand for the rating periods for each month shall be the maximum average load in kilowatts during any fifteen-minute period as indicated by a time-of-use meter. The kilowatts of billing demand for each month shall be the maximum measured demand outside of the Off-Peak hours, but not less than 200 kW.

Power Factor:

The above energy and demand charges are based upon an average monthly power factor of 85%. For each 1% the average power factor is above or below 85%, the monthly energy and demand charges as computed under the above rates shall be decreased or increased, respectively, by 0.15%

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SCHEDULE TOU-P - (continued)

Power Factor - continued:

The average monthly power factor will be determined from the readings of a kWhr meter and kvarh meter, and will be computed to the nearest whole percent and not exceeding 100% for the purpose of computing the adjustment. The kvarh meter shall be ratcheted to prevent reversal in the event the power factor is leading at any time.

Supply Voltage Delivery:

If the customer takes delivery at the Company's supply line voltage, the demand and energy charges will be decreased as follows:

Transmission voltage supplied without further transformation -4.0%
Distribution voltage supplied without further transformation -2.5%

Metering will normally be at the delivery voltage. When the customer's transformers are adjacent to the delivery point, the customer may elect to be metered at a single point on the secondary side of his transformers where such point is approved by the Company. When the energy is metered on the secondary side of the customer's transformers, the above decreases will be 3.1% and 0.6%, respectively.

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer, Demand, and Energy charges.

Integrated Resource Planning Cost Recovery Provision:

The Integrated Resource Planning Surcharge shall be added to the Customer, Demand, and Energy charges, and energy cost adjustment.

Rules and Regulations:

Service supplied under this rate shall be subject to the Rules and Regulations of the Company.

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SCHEDULE TOU-R

RESIDENTIAL TIME-OF-USE SERVICE

AVAILABILITY:

Applicable to residential service metered and billed separately by the Company. This Schedule does not apply where a residence and business are combined. Service under this Schedule will be delivered at secondary voltages as specified by the Company.

RATES:

CUSTOMER CHARGE - $ per customer per month:

Single-Phase Service	- per month	$7.50/month
Three-Phase Service	- per month	$12.00/month

ENERGY CHARGES - ¢ per kWh:

<u>Time-of-Use Charges</u>

On-Peak Period - per kWhr	31.3681 ¢/kWhr
Off-Peak Period - per kWhr	10.3681 ¢/kWhr

<u>Usage Charges - </u>¢ per kWh:

All kWhr between 350 - 1200 kWhr per month	1.00 ¢/kWhr
All kWhr over 1200 kWhr per month	1.25 ¢/kWhr

MINIMUM CHARGE:

The minimum charge shall be $17.00

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SCHEDULE TOU-R (Continued)

TIME-OF-USE RATING PERIODS:

The time-of-use rating periods under this Schedule shall be defined as follows:

On-Peak:	3:00 p.m.-8:00 p.m., Daily
Off-Peak	8:00 p.m.-3:00 p.m., Daily

DETERMINATION OF TIME-OF-USE ENERGY:

The Company shall install, own, operate and maintain a time-of-use meter to measure the customer's kWhr energy consumption during the time-of-use rating periods.

TERMS AND CONDITIONS:

1) The Company may meter the customer's energy usage pattern for one to two months before the customer's service start date under this Schedule, to allow the Company to gather the customer's baseline load profile.

2) The Company shall install the time-of-use meter in accordance with Rule 14. Although the existing service equipment is expected to be used, the customer shall provide, install, and maintain the service equipment specified in Rule 14, such as all the conductors, service switches, meter socket, meter panel, and other similar devices required for service connection and meter installations on the customer's premises.

3) The Company may request a customer to allow the Company shared-use of its telephone line to enable the Company to remotely download the customer's usage data from the meter.

MAUI DIVISION

SCHEDULE TOU-R (Continued)

4) A customer may terminate service under this rate Schedule and return to the regular Schedule R at any time without penalty, by a written notice to the Company. The change shall become effective at the start of the next regular billing period following the date of receipt by the Company of the notice from the customer. If a customer elects to discontinue service under this Schedule, the customer will not be permitted to return to this Schedule for a period of one year.

ENERGY COST ADJUSTMENT CLAUSE:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer and Energy Charges.

INTEGRATED RESOURCE PLANNING COST RECOVERY PROVISION:

The Integrated Resource Planning Surcharge shall be added to the Customer and Energy Charges, and energy cost adjustment.

RULES AND REGULATIONS:

Service supplied under this rate schedule shall be subject to the Rules and Regulations of the Company.

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SCHEDULE TOU-G

SMALL COMMERCIAL TIME-OF-USE SERVICE

AVAILABILITY:

Applicable to general light and/or power loads less than or equal to 5,000 kilowatthours per month, and less than or equal to 25 kilowatts, and supplied through a single meter. Customers served under this Schedule who exceed 5,000 kilowatthours per month or 25 kilowatts will be automatically transferred to Schedule TOU-J at the beginning of the next billing period.

Service will be delivered at secondary voltages as specified by the Company, except where the nature or location of the customer's load makes delivery at secondary voltage impractical, the Company may, at its option, deliver the service at a nominal primary voltage as specified by the Company.

RATE:

CUSTOMER CHARGE:

Single-Phase Service - per month	\$25.00/month
Three-Phase Service - per month	\$40.00/month

ENERGY CHARGE: (To be added to Customer and Demand Charge)

Priority Peak Period	- per kWhr	20.8497 ¢/kWhr
Mid-Peak Period	- per kWhr	18.3497 ¢/kWhr
Off-Peak Period	- per kWhr	10.8497 ¢/kWhr

MINIMUM CHARGE: Customer Charge

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SCHEDULE TOU-G - continued

TIME-OF-USE RATING PERIODS:

The time-of-use rating periods shall be as follows:

Priority Peak:	5:00 p.m. - 9:00 p.m.,	Monday - Friday
Mid-Peak:	7:00 a.m. - 5:00 p.m.,	Monday - Friday
	7:00 a.m. - 9:00 p.m.,	Saturday - Sunday
Off-Peak:	9:00 p.m. - 7:00 a.m.,	Daily

DETERMINATION OF TIME-OF-USE ENERGY:

The Company shall install, own, operate and maintain a time-of-use meter to measure the customer's kWhr energy consumption during the time-of-use rating periods.

TERMS AND CONDITIONS:

1) The Company may meter the customer's energy usage pattern for one to two months before the customer's service start date under this Schedule, to allow the Company to gather the customer's baseline load profile.

2) The Company shall install the time-of-use meter in accordance with Rule 14. Although the existing service equipment is expected to be used, the customer shall provide, install, and maintain the service equipment specified in Rule 14, such as all the conductors, service switches, meter socket, meter panel, and other similar devices required for service connection and meter installations on the customer's premises.

3) The Company may request a customer to allow the Company shared-use of its telephone line to enable the Company to remotely download the customer's usage data from the meter.

MAUI DIVISION

SCHEDULE TOU-G - continued

4) A customer may terminate service under this rate Schedule and return to the regular Schedule G at any time without penalty, by a written notice to the Company. The change shall become effective at the start of the next regular billing period following the date of receipt by the Company of the notice from the customer. If a customer elects to discontinue service under this Schedule, the customer will not be permitted to return to this Schedule for a period of one year.

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer, Demand, and Energy charges.

Integrated Resource Planning Cost Recovery Provision:

The Integrated Resource Planning Surcharge shall be added to the Customer, Demand, and Energy charges, and energy cost adjustment.

Rules and Regulations:

Service supplied under this rate shall be subject to the Rules and Regulations of the Company.

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SCHEDULE TOU-J

COMMERCIAL TIME-OF-USE SERVICE

AVAILABILITY:

Applicable to general light and/or power loads which exceed 5,000 kilowatthours per month three times within a twelve-month period or which exceed 25 kW per month and but are less than 200 kW per month. This Schedule cannot be used in conjunction with load management Riders M, T, and I, Schedule U, and Schedule TOU-P.

RATE:

CUSTOMER CHARGE:

Single-Phase Service	- per month	$55.00/month
Three-Phase Service	- per month	$70.00/month

DEMAND CHARGE - (To be added to Customer and Energy Charge)

Priority Peak	- per kW of billing demand	$11.50/kW
Mid-Peak	- per kW of billing demand	$7.50/kW

The customer shall be billed the Priority Peak demand charge if his maximum measured kW demand for the billing period occurs during the priority peak period. If the customer's maximum measured kW demand for the billing period occurs during the Mid-Peak period, the Mid-Peak demand charge will apply. If the customer's maximum kW demand during the Priority Peak period is equal to his maximum kW demand during the Mid-Peak period, the Priority Peak demand charge shall apply.

ENERGY CHARGE: (To be added to Customer Charge)

Priority Peak Period	- per kWhr	18.5784 ¢/kWhr
Mid-Peak Period	- per kWhr	16.5784 ¢/kWhr
Off-Peak Period	- per kWhr	6.5784 ¢/kWhr

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SCHEDULE TOU-J - (continued)

MINIMUM CHARGE:

The minimum charge per month shall be the sum of the Customer Charge and the Demand Charge. The Demand Charge shall be computed with the above demand charge applied to kilowatts of demand. The kilowatts of demand for the minimum charge calculation each month shall not be less than 25 kW.

TIME-OF-USE RATING PERIODS:

The time-of-use rating periods shall be as follows:

Priority Peak:	5:00 p.m. - 9:00 p.m., Monday - Friday
Mid-Peak:	7:00 a.m. - 5:00 p.m., Monday - Friday
	7:00 a.m. - 9:00 p.m., Saturday - Sunday
Off-Peak:	9:00 p.m. - 7:00 a.m., Daily

DETERMINATION OF TIME-OF-USE ENERGY AND DEMAND:

The Company shall install a time-of-use meter to measure the customer's kilowatthour consumption and kilowatt load during the time-of-use rating periods. The maximum demand for the rating periods for each month shall be the maximum average load in kilowatts during any fifteen-minute period as indicated by a time-of-use meter. The kilowatts of billing demand for each month shall be the maximum measured demand outside of the Off-Peak hours, but not less than 25 kW.

Power Factor:

The above energy and demand charges are based upon an average monthly power factor of 85%. For each 1% the average power factor is above or below 85%, the monthly energy and demand charges as computed under the above rates shall be decreased or increased, respectively, by 0.10%.

SHEET NO. 85B
Effective

MAUI DIVISION

SCHEDULE TOU-J - (continued)

Power Factor - continued:

The average monthly power factor will be determined from the readings of a kWhr meter and kvarh meter, and will be computed to the nearest whole percent and not exceeding 100% for the purpose of computing the adjustment. The kvarh meter shall be ratcheted to prevent reversal in the event the power factor is leading at any time.

Supply Voltage Delivery:

If the customer takes delivery at the Company's supply line voltage, the demand and energy charges will be decreased as follows:

Transmission voltage supplied without further transformation	-4.4%
Distribution voltage supplied without further transformation	-1.1%

Metering will normally be at the delivery voltage. When the customer's transformers are adjacent to the delivery point, the customer may elect to be metered at a single point on the secondary side of his transformers where such point is approved by the Company. When the energy is metered on the secondary side of the customer's transformers, the above decreases will be 3.8% and 0.5%, respectively.

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer, Demand, and Energy charges.

Integrated Resource Planning Cost Recovery Provision:

The Integrated Resource Planning Surcharge shall be added to the Customer, Demand, and Energy charges, and energy cost adjustment.

Rules and Regulations:

Service supplied under this rate shall be subject to the Rules and Regulations of the Company.

SHEET NO. 86
Effective

MAUI DIVISION

SCHEDULE TOU-P

LARGE POWER TIME-OF-USE SERVICE

AVAILABILITY:

Applicable to large light and/or power service supplied and metered at a single voltage and delivery point. Loads must exceed 200 kW per month. This Schedule cannot be used in conjunction with load management Riders M, T, and I, and Schedule TOU-P.

RATE:

CUSTOMER CHARGE: $310.00 per month

DEMAND CHARGE - (To be added to Customer and Energy Charge)

Priority Peak	- per kW of billing demand	$17.50/kW
Mid-Peak	- per kW of billing demand	$16.00/kW

The customer shall be billed the Priority Peak demand charge if his maximum measured kW demand for the billing period occurs during the priority peak period. If the customer's maximum measured kW demand for the billing period occurs during the Mid-Peak period, the Mid-Peak demand charge will apply. If the customer's maximum kW demand during the Priority Peak period is equal to his maximum kW demand during the Mid-Peak period, the Priority Peak demand charge shall apply.

ENERGY CHARGE: (To be added to Customer Charge)

Priority Peak Period	- per kWhr	15.6881 ¢/kWhr
Mid-Peak Period	- per kWhr	13.6881 ¢/kWhr
Off-Peak Period	- per kWhr	3.6881 ¢/kWhr

SHEET NO. 86A
Effective

MAUI DIVISION

SCHEDULE TOU-P - (continued)

MINIMUM CHARGE:

The minimum charge per month shall be the sum of the Customer Charge and the Demand Charge. The Demand Charge shall be computed with the above demand charge applied to kilowatts of demand. The kilowatts of demand for the minimum charge calculation each month shall not be less than 200 kW.

TIME-OF-USE RATING PERIODS:

The time-of-use rating periods shall be as follows:

Priority Peak:	5:00 p.m. - 9:00 p.m., Monday - Friday
Mid-Peak:	7:00 a.m. - 5:00 p.m., Monday - Friday
	7:00 a.m. - 9:00 p.m., Saturday - Sunday
Off-Peak:	9:00 p.m. - 7:00 a.m., Daily

DETERMINATION OF TIME-OF-USE ENERGY AND DEMAND:

The Company shall install a time-of-use meter to measure the customer's kilowatthour consumption and kilowatt load during the time-of-use rating periods. The maximum demand for the rating periods for each month shall be the maximum average load in kilowatts during any fifteen-minute period as indicated by a time-of-use meter. The kilowatts of billing demand for each month shall be the maximum measured demand outside of the Off-Peak hours, but not less than 200 kW.

Power Factor:

The above energy and demand charges are based upon an average monthly power factor of 85%. For each 1% the average power factor is above or below 85%, the monthly energy and demand charges as computed under the above rates shall be decreased or increased, respectively, by 0.10%.

MAUI DIVISION

SCHEDULE TOU-P - (continued)

Power Factor - continued:

The average monthly power factor will be determined from the readings of a kWhr meter and kvarh meter, and will be computed to the nearest whole percent and not exceeding 100% for the purpose of computing the adjustment. The kvarh meter shall be ratcheted to prevent reversal in the event the power factor is leading at any time.

Supply Voltage Delivery:

If the customer takes delivery at the Company's supply line voltage, the demand and energy charges will be decreased as follows:

Transmission voltage supplied without further transformation	-4.4%
Distribution voltage supplied without further transformation	-1.1%

Metering will normally be at the delivery voltage. When the customer's transformers are adjacent to the delivery point, the customer may elect to be metered at a single point on the secondary side of his transformers where such point is approved by the Company. When the energy is metered on the secondary side of the customer's transformers, the above decreases will be 3.8% and 0.5%, respectively.

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer, Demand, and Energy charges.

Integrated Resource Planning Cost Recovery Provision:

The Integrated Resource Planning Surcharge shall be added to the Customer, Demand, and Energy charges, and energy cost adjustment.

Rules and Regulations:

Service supplied under this rate shall be subject to the Rules and Regulations of the Company.

SHEET NO. 95
Effective

LANAI DIVISION

SCHEDULE TOU-R

RESIDENTIAL TIME-OF-USE SERVICE

AVAILABILITY:

Applicable to residential service metered and billed separately by the Company. This Schedule does not apply where a residence and business are combined. Service under this Schedule will be delivered at secondary voltages as specified by the Company.

RATES:

CUSTOMER CHARGE - $ per customer per month:

Single-Phase Service	- per month	$7.50/month
Three-Phase Service	- per month	$12.00/month

ENERGY CHARGES - ¢ per kWhr:

Time-of-Use Charges

On-Peak Period - per kWhr	36.3375 ¢/kWhr
Off-Peak Period - per kWhr	15.3375 ¢/kWhr

Usage Charges ¢ per kWh:

All kWhr between 250 - 750 kWhr per month	0.5 ¢/kWhr
All kWh over 750 kWhr per month	1.25 ¢/kWhr

MINIMUM CHARGE:

The minimum charge shall be $17.00.

SHEET NO. 95A
Effective

LANAI DIVISION

SCHEDULE TOU-R (Continued)

TIME-OF-USE RATING PERIODS:

The time-of-use rating periods under this Schedule shall be defined as follows:

On-Peak:	3:00 p.m. - 8:00 p.m., Daily
Off-Peak:	8:00 p.m. - 3:00 p.m., Daily

DETERMINATION OF TIME-OF-USE ENERGY:

The Company shall install, own, operate and maintain a time-of-use meter to measure the customer's kWhr energy consumption during the time-of-use rating periods.

TERMS AND CONDITIONS:

1) The Company may meter the customer's energy usage pattern for one to two months before the customer's service start date under this Schedule, to allow the Company to gather the customer's baseline load profile.

2) The Company shall install the time-of-use meter in accordance with Rule 14. Although the existing service equipment is expected to be used, the customer shall provide, install, and maintain the service equipment specified in Rule 14, such as all the conductors, service switches, meter socket, meter panel, and other similar devices required for service connection and meter installations on the customer's premises.

3) The Company may request a customer to allow the Company shared-use of its telephone line to enable the Company to remotely download the customer's usage data from the meter.

SHEET NO. 95B
Effective

LANAI DIVISION

SCHEDULE TOU-R (Continued)

4) A customer may terminate service under this rate Schedule and return to the regular Schedule R at any time without penalty, by a written notice to the Company. The change shall become effective at the start of the next regular billing period following the date of receipt by the Company of the notice from the customer. If a customer elects to discontinue service under this Schedule, the customer will not be permitted to return to this Schedule for a period of one year.

ENERGY COST ADJUSTMENT CLAUSE:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer and Energy Charges.

INTEGRATED RESOURCE PLANNING COST RECOVERY PROVISION:

The Integrated Resource Planning Surcharge shall be added to the Customer and Energy Charges, and energy cost adjustment.

RULES AND REGULATIONS:

Service supplied under this rate schedule shall be subject to the Rules and Regulations of the Company.

SHEET NO. 96
Effective

LANAI DIVISION

SCHEDULE TOU-G

SMALL COMMERCIAL TIME-OF-USE SERVICE

AVAILABILITY:

Applicable to general light and/or power loads less than or equal to 5,000 kilowatthours per month, and less than or equal to 25 kilowatts, and supplied through a single meter. Customers served under this Schedule who exceed 5,000 kilowatthours per month or 25 kilowatts will be automatically transferred to Schedule TOU-J at the beginning of the next billing period.

Service will be delivered at secondary voltages as specified by the Company, except where the nature or location of the customer's load makes delivery at secondary voltage impractical, the Company may, at its option, deliver the service at a nominal primary voltage as specified by the Company.

RATE:

CUSTOMER CHARGE:

Single-Phase Service - per month	$30.00/month
Three-Phase Service - per month	$45.00/month

ENERGY CHARGE: (To be added to Customer and Demand Charge)

Priority Peak Period	- per kWhr	26.4932 ¢/kWhr
Mid-Peak Period	- per kWhr	23.9932 ¢/kWhr
Off-Peak Period	- per kWhr	16.4932 ¢/kWhr

MINIMUM CHARGE: Customer Charge

SHEET NO. 96A
Effective

LANAI DIVISION

SCHEDULE TOU-G - continued

TIME-OF-USE RATING PERIODS:

The time-of-use rating periods shall be as follows:

Priority Peak:	5:00 p.m. - 9:00 p.m., Monday - Friday
Mid-Peak:	7:00 a.m. - 5:00 p.m., Monday - Friday
	7:00 a.m. - 9:00 p.m., Saturday - Sunday
Off-Peak:	9:00 p.m. - 7:00 a.m., Daily

DETERMINATION OF TIME-OF-USE ENERGY:

The Company shall install, own, operate and maintain a time-of-use meter to measure the customer's kWhr energy consumption during the time-of-use rating periods.

TERMS AND CONDITIONS:

1) The Company may meter the customer's energy usage pattern for one to two months before the customer's service start date under this Schedule, to allow the Company to gather the customer's baseline load profile.

2) The Company shall install the time-of-use meter in accordance with Rule 14. Although the existing service equipment is expected to be used, the customer shall provide, install, and maintain the service equipment specified in Rule 14, such as all the conductors, service switches, meter socket, meter panel, and other similar devices required for service connection and meter installations on the customer's premises.

3) The Company may request a customer to allow the Company shared-use of its telephone line to enable the Company to remotely download the customer's usage data from the meter.

4) A customer may terminate service under this rate Schedule and return to the regular Schedule G at any time without penalty, by a written notice to the Company. The change shall become effective at the start of the next regular billing period following the date of receipt by the Company of the notice from the customer. If a customer elects to discontinue service under this Schedule, the customer will not be permitted to return to this Schedule for a period of one year.

SHEET NO. 96B
Effective

LANAI DIVISION

SCHEDULE TOU-G - continued

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer, Demand, and Energy charges.

Integrated Resource Planning Cost Recovery Provision:

The Integrated Resource Planning Surcharge shall be added to the Customer, Demand, and Energy charges, and energy cost adjustment.

Rules and Regulations:

Service supplied under this rate shall be subject to the Rules and Regulations of the Company.

SHEET NO. 97
Effective

LANAI DIVISION

SCHEDULE TOU-J

COMMERCIAL TIME-OF-USE SERVICE

AVAILABILITY:

Applicable to general light and/or power loads which exceed 5,000 kilowatthours per month three times within a twelve-month period or which exceed 25 kW per month and but are less than 200 kW per month. This Schedule cannot be used in conjunction with load management Riders M, T, and I, Schedule "U", and Schedule "TOU-P".

RATE:

CUSTOMER CHARGE:

Single-Phase Service	- per month	$55.00/month
Three-Phase Service	- per month	$70.00/month

DEMAND CHARGE - (To be added to Customer and Energy Charge)

Priority Peak	- per kW of billing demand	$12.00/kW
Mid-Peak	- per kW of billing demand	$7.50/kW

The customer shall be billed the Priority Peak demand charge if his maximum measured kW demand for the billing period occurs during the priority peak period. If the customer's maximum measured kW demand for the billing period occurs during the Mid-Peak period, the Mid-Peak demand charge will apply. If the customer's maximum kW demand during the Priority Peak period is equal to his maximum kW demand during the Mid-Peak period, the Priority Peak demand charge shall apply.

ENERGY CHARGE: (To be added to Customer Charge)

Priority Peak Period	- per kWhr	27.1335 ¢/kWhr
Mid-Peak Period	- per kWhr	25.1335 ¢/kWhr
Off-Peak Period	- per kWhr	15.1335 ¢/kWhr

SHEET NO. 97A
Effective

LANAI DIVISION

SCHEDULE TOU-J - (continued)

MINIMUM CHARGE:

The minimum charge per month shall be the sum of the Customer Charge and the Demand Charge. The Demand Charge shall be computed with the above demand charge applied to kilowatts of demand. The kilowatts of demand for the minimum charge calculation each month shall not be less than 25 kW.

TIME-OF-USE RATING PERIODS:

The time-of-use rating periods shall be as follows:

Priority Peak:	5:00 p.m. - 9:00 p.m., Monday - Friday
Mid-Peak:	7:00 a.m. - 5:00 p.m., Monday - Friday
	7:00 a.m. - 9:00 p.m., Saturday - Sunday
Off-Peak:	9:00 p.m. - 7:00 a.m., Daily

DETERMINATION OF TIME-OF-USE ENERGY AND DEMAND:

The Company shall install a time-of-use meter to measure the customer's kilowatthour consumption and kilowatt load during the time-of-use rating periods. The maximum demand for the rating periods for each month shall be the maximum average load in kilowatts during any fifteen-minute period as indicated by a time-of-use meter. The kilowatts of billing demand for each month shall be the maximum measured demand outside of the Off-Peak hours, but not less than 25 kW.

Power Factor:

The above energy and demand charges are based upon an average monthly power factor of 85%. For each 1% the average power factor is above or below 85%, the monthly energy and demand charges as computed under the above rates shall be decreased or increased, respectively, by 0.15%.

SHEET NO. 97B
Effective

LANAI DIVISION

SCHEDULE TOU-J - (continued)

Power Factor - continued:

The average monthly power factor will be determined from the readings of a kWhr meter and kvarh meter, and will be computed to the nearest whole percent and not exceeding 100% for the purpose of computing the adjustment. The kvarh meter shall be ratcheted to prevent reversal in the event the power factor is leading at any time.

Supply Voltage Delivery:

If the customer takes delivery at the Company's supply line voltage, the demand and energy charges will be decreased as follows:

Transmission voltage supplied without further transformation	-4.4%
Distribution voltage supplied without further transformation	-1.1%

Metering will normally be at the delivery voltage. When the customer's transformers are adjacent to the delivery point, the customer may elect to be metered at a single point on the secondary side of his transformers where such point is approved by the Company. When the energy is metered on the secondary side of the customer's transformers, the above decreases will be 3.8% and 0.5%, respectively.

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer, Demand, and Energy charges.

Integrated Resource Planning Cost Recovery Provision:

The Integrated Resource Planning Surcharge shall be added to the Customer, Demand, and Energy charges, and energy cost adjustment.

Rules and Regulations:

Service supplied under this rate shall be subject to the Rules and Regulations of the Company.

SHEET NO. 98
Effective

LANAI DIVISION

SCHEDULE TOU-P

LARGE POWER TIME-OF-USE SERVICE

AVAILABILITY:

Applicable to large light and/or power service supplied and metered at a single voltage and delivery point. Loads must exceed 200 kW per month. This Schedule cannot be used in conjunction with load management Riders M, T, and I, and Schedule "TOU-P".

RATE:

CUSTOMER CHARGE:	$210.00 per month

DEMAND CHARGE - (To be added to Customer and Energy Charge)

Priority Peak	- per kW of billing demand	$40.00/kW
Mid-Peak	- per kW of billing demand	$20.00/kW

The customer shall be billed the Priority Peak demand charge if his maximum measured kW demand for the billing period occurs during the priority peak period. If the customer's maximum measured kW demand for the billing period occurs during the Mid-Peak period, the Mid-Peak demand charge will apply. If the customer's maximum kW demand during the Priority Peak period is equal to his maximum kW demand during the Mid-Peak period, the Priority Peak demand charge shall apply.

ENERGY CHARGE: (To be added to Customer Charge)

Priority Peak Period	- per kWhr	23.3145 ¢/kWhr
Mid-Peak Period	- per kWhr	21.3145 ¢/kWhr
Off-Peak Period	- per kWhr	11.3145 ¢/kWhr

LANAI DIVISION

SCHEDULE TOU-P - (continued)

MINIMUM CHARGE:

The minimum charge per month shall be the sum of the Customer Charge and the Demand Charge. The Demand Charge shall be computed with the above demand charge applied to kilowatts of demand. The kilowatts of demand for the minimum charge calculation each month shall not be less than 200 kW.

TIME-OF-USE RATING PERIODS:

The time-of-use rating periods shall be as follows:

Priority Peak:	5:00 p.m. - 9:00 p.m., Monday - Friday
Mid-Peak:	7:00 a.m. - 5:00 p.m., Monday - Friday
	7:00 a.m. - 9:00 p.m., Saturday - Sunday
Off-Peak:	9:00 p.m. - 7:00 a.m., Daily

DETERMINATION OF TIME-OF-USE ENERGY AND DEMAND:

The Company shall install a time-of-use meter to measure the customer's kilowatthour consumption and kilowatt load during the time-of-use rating periods. The maximum demand for the rating periods for each month shall be the maximum average load in kilowatts during any fifteen-minute period as indicated by a time-of-use meter. The kilowatts of billing demand for each month shall be the maximum measured demand outside of the Off-Peak hours, but not less than 200 kW.

Power Factor:

The above energy and demand charges are based upon an average monthly power factor of 85%. For each 1% the average power factor is above or below 85%, the monthly energy and demand charges as computed under the above rates shall be decreased or increased, respectively, by 0.10%.

SHEET NO. 98B
Effective

LANAI DIVISION

SCHEDULE TOU-P - (continued)

Power Factor - continued:

The average monthly power factor will be determined from the readings of a kWhr meter and kvarh meter, and will be computed to the nearest whole percent and not exceeding 100% for the purpose of computing the adjustment. The kvarh meter shall be ratcheted to prevent reversal in the event the power factor is leading at any time.

Supply Voltage Delivery:

If the customer takes delivery at the Company's supply line voltage, the demand and energy charges will be decreased as follows:

Transmission voltage supplied without further transformation	-4.4%
Distribution voltage supplied without further transformation	-1.1%

Metering will normally be at the delivery voltage. When the customer's transformers are adjacent to the delivery point, the customer may elect to be metered at a single point on the secondary side of his transformers where such point is approved by the Company. When the energy is metered on the secondary side of the customer's transformers, the above decreases will be 3.8% and 0.5%, respectively.

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer, Demand, and Energy charges.

Integrated Resource Planning Cost Recovery Provision:

The Integrated Resource Planning Surcharge shall be added to the Customer, Demand, and Energy charges, and energy cost adjustment.

Rules and Regulations:

Service supplied under this rate shall be subject to the Rules and Regulations of the Company.

SHEET NO. 135
Effective

MOLOKAI DIVISION

SCHEDULE TOU-R

RESIDENTIAL TIME-OF-USE SERVICE

AVAILABILITY:

Applicable to residential service metered and billed separately by the Company. This Schedule does not apply where a residence and business are combined. Service under this Schedule will be delivered at secondary voltages as specified by the Company.

RATES:

CUSTOMER CHARGE - $ per customer per month:

Single-Phase Service	- per month	$7.50/month
Three-Phase Service	- per month	$12.00/month

ENERGY CHARGES - ¢ per kWh:

Time-of-Use Charges		
On-Peak Period	- per kWhr	35.5992 ¢/kWhr
Off-Peak Period	- per kWhr	14.5992 ¢/kWhr

Usage Charges - ¢ per kWh:	
All kWhr between 250 - 750 kWhr per month -	1.25 ¢/kWhr
All kWh over 750 kWhr per month -	1.50 ¢/kWhr

MINIMUM CHARGE:

The minimum charge shall be $17.00.

SHEET NO. 135A
Effective

MOLOKAI DIVISION

SCHEDULE TOU-R (Continued)

TIME-OF-USE RATING PERIODS:

The time-of-use rating periods under this Schedule shall be defined as follows:

On-Peak:	3:00 p.m.- 8:00 p.m., daily
Off-Peak:	8:00 p.m.- 3:00 p.m., daily

DETERMINATION OF TIME-OF-USE ENERGY:

The Company shall install, own, operate and maintain a time-of-use meter to measure the customer's kWhr energy consumption during the time-of-use rating periods.

TERMS AND CONDITIONS:

1) The Company may meter the customer's energy usage pattern for one to two months before the customer's service start date under this Schedule, to allow the Company to gather the customer's baseline load profile.

2) The Company shall install the time-of-use meter in accordance with Rule 14. Although the existing service equipment is expected to be used, the customer shall provide, install, and maintain the service equipment specified in Rule 14, such as all the conductors, service switches, meter socket, meter panel, and other similar devices required for service connection and meter installations on the customer's premises.

3) The Company may request a customer to allow the Company shared-use of its telephone line to enable the Company to remotely download the customer's usage data from the meter.

SHEET NO. 135B
Effective

MOLOKAI DIVISION

SCHEDULE TOU-R (Continued)

4) A customer may terminate service under this rate Schedule and return to the regular Schedule R at any time without penalty, by a written notice to the Company. The change shall become effective at the start of the next regular billing period following the date of receipt by the Company of the notice from the customer. If a customer elects to discontinue service under this Schedule, the customer will not be permitted to return to this Schedule for a period of one year.

ENERGY COST ADJUSTMENT CLAUSE:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer and Energy Charges.

INTEGRATED RESOURCE PLANNING COST RECOVERY PROVISION:

The Integrated Resource Planning Surcharge shall be added to the Customer and Energy Charges, and energy cost adjustment.

RULES AND REGULATIONS:

Service supplied under this rate schedule shall be subject to the Rules and Regulations of the Company.

SHEET NO. 136
Effective

MOLOKAI DIVISION

SCHEDULE TOU-G

SMALL COMMERCIAL TIME-OF-USE SERVICE

AVAILABILITY:

Applicable to general light and/or power loads less than or equal to 5,000 kilowatthours per month, and less than or equal to 25 kilowatts, and supplied through a single meter. Customers served under this Schedule who exceed 5,000 kilowatthours per month or 25 kilowatts will be automatically transferred to Schedule TOU-J at the beginning of the next billing period.

Service will be delivered at secondary voltages as specified by the Company, except where the nature or location of the customer's load makes delivery at secondary voltage impractical, the Company may, at its option, deliver the service at a nominal primary voltage as specified by the Company.

RATE:

CUSTOMER CHARGE:

Single-Phase Service - per month	$23.00/month
Three-Phase Service - per month	$34.00/month

ENERGY CHARGE: (To be added to Customer and Demand Charge)

Priority Peak Period	- per kWhr	30.9988 ¢/kWhr
Mid-Peak Period	- per kWhr	28.4988 ¢/kWhr
Off-Peak Period	- per kWhr	20.9988 ¢/kWhr

MINIMUM CHARGE: Customer Charge

SHEET NO. 136A
Effective

MOLOKAI DIVISION

SCHEDULE TOU-G - continued

TIME-OF-USE RATING PERIODS:

The time-of-use rating periods shall be as follows:

Priority Peak:	5:00 p.m. - 9:00 p.m., Monday - Friday
Mid-Peak:	7:00 a.m. - 5:00 p.m., Monday - Friday
	7:00 a.m. - 9:00 p.m., Saturday - Sunday
Off-Peak:	9:00 p.m. - 7:00 a.m., Daily

DETERMINATION OF TIME-OF-USE ENERGY:

The Company shall install, own, operate and maintain a time-of-use meter to measure the customer's kWhr energy consumption during the time-of-use rating periods.

TERMS AND CONDITIONS:

1) The Company may meter the customer's energy usage pattern for one to two months before the customer's service start date under this Schedule, to allow the Company to gather the customer's baseline load profile.

2) The Company shall install the time-of-use meter in accordance with Rule 14. Although the existing service equipment is expected to be used, the customer shall provide, install, and maintain the service equipment specified in Rule 14, such as all the conductors, service switches, meter socket, meter panel, and other similar devices required for service connection and meter installations on the customer's premises.

3) The Company may request a customer to allow the Company shared-use of its telephone line to enable the Company to remotely download the customer's usage data from the meter.

4) A customer may terminate service under this rate Schedule and return to the regular Schedule G at any time without penalty, by a written notice to the Company. The change shall become effective at the start of the next regular billing period following the date of receipt by the Company of the notice from the customer. If a customer elects to discontinue service under this Schedule, the customer will not be permitted to return to this Schedule for a period of one year.

SHEET NO. 136B
Effective

MOLOKAI DIVISION

SCHEDULE TOU-G - continued

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer, Demand, and Energy charges.

Integrated Resource Planning Cost Recovery Provision:

The Integrated Resource Planning Surcharge shall be added to the Customer, Demand, and Energy charges, and energy cost adjustment.

Rules and Regulations:

Service supplied under this rate shall be subject to the Rules and Regulations of the Company.

SHEET NO. 137
Effective

MOLOKAI DIVISION

SCHEDULE TOU-J

COMMERCIAL TIME-OF-USE SERVICE

AVAILABILITY:

Applicable to general light and/or power loads which exceed 5,000 kilowatthours per month three times within a twelve-month period or which exceed 25 kW per month and but are less than 100 kW per month. This Schedule cannot be used in conjunction with load management Riders M, T, and I, Schedule "U", and Schedule "TOU-P".

RATE:

CUSTOMER CHARGE:

Single-Phase Service	- per month	$42.00/month
Three-Phase Service	- per month	$52.00/month

DEMAND CHARGE - (To be added to Customer and Energy Charge)

Priority Peak	- per kW of billing demand	$18.90/kW
Mid-Peak	- per kW of billing demand	$6.15/kW

The customer shall be billed the Priority Peak demand charge if his maximum measured kW demand for the billing period occurs during the priority peak period. If the customer's maximum measured kW demand for the billing period occurs during the Mid-Peak period, the Mid-Peak demand charge will apply. If the customer's maximum kW demand during the Priority Peak period is equal to his maximum kW demand during the Mid-Peak period, the Priority Peak demand charge shall apply.

ENERGY CHARGE: (To be added to Customer Charge)

Priority Peak Period	- per kWhr	24.5832 ¢/kWhr
Mid-Peak Period	- per kWhr	22.5832 ¢/kWhr
Off-Peak Period	- per kWhr	12.5832 ¢/kWhr

SHEET NO. 137A
Effective

MOLOKAI DIVISION

SCHEDULE TOU-J - (continued)

MINIMUM CHARGE:

The minimum charge per month shall be the sum of the Customer Charge and the Demand Charge. The Demand Charge shall be computed with the above demand charge applied to kilowatts of demand. The kilowatts of demand for the minimum charge calculation each month shall not be less than 25 kW.

TIME-OF-USE RATING PERIODS:

The time-of-use rating periods shall be as follows:

Priority Peak:	5:00 p.m. - 9:00 p.m., Monday - Friday
Mid-Peak:	7:00 a.m. - 5:00 p.m., Monday - Friday
	7:00 a.m. - 9:00 p.m., Saturday - Sunday
Off-Peak:	9:00 p.m. - 7:00 a.m., Daily

DETERMINATION OF TIME-OF-USE ENERGY AND DEMAND:

The Company shall install a time-of-use meter to measure the customer's kilowatthour consumption and kilowatt load during the time-of-use rating periods. The maximum demand for the rating periods for each month shall be the maximum average load in kilowatts during any fifteen-minute period as indicated by a time-of-use meter. The kilowatts of billing demand for each month shall be the maximum measured demand outside of the Off-Peak hours, but not less than 25 kW.

Power Factor:

The above energy and demand charges are based upon an average monthly power factor of 85%. For each 1% the average power factor is above or below 85%, the monthly energy and demand charges as computed under the above rates shall be decreased or increased, respectively, by 0.15%.

SHEET NO. 137B
Effective

MOLOKAI DIVISION

SCHEDULE TOU-J - (continued)

Power Factor - continued:

The average monthly power factor will be determined from the readings of a kWhr meter and kvarh meter, and will be computed to the nearest whole percent and not exceeding 100% for the purpose of computing the adjustment. The kvarh meter shall be ratcheted to prevent reversal in the event the power factor is leading at any time.

Supply Voltage Delivery:

If the customer takes delivery at the Company's supply line voltage, the demand and energy charges will be decreased as follows:

Transmission voltage supplied without further transformation	-4.4%
Distribution voltage supplied without further transformation	-1.1%

Metering will normally be at the delivery voltage. When the customer's transformers are adjacent to the delivery point, the customer may elect to be metered at a single point on the secondary side of his transformers where such point is approved by the Company. When the energy is metered on the secondary side of the customer's transformers, the above decreases will be 3.8% and 0.5%, respectively.

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer, Demand, and Energy charges.

Integrated Resource Planning Cost Recovery Provision:

The Integrated Resource Planning Surcharge shall be added to the Customer, Demand, and Energy charges, and energy cost adjustment.

Rules and Regulations:

Service supplied under this rate shall be subject to the Rules and Regulations of the Company.

MAUI ELECTRIC COMPANY, LIMITED

SHEET NO. 138
Effective

MOLOKAI DIVISION

SCHEDULE TOU-P

LARGE POWER TIME-OF-USE SERVICE

AVAILABILITY:

Applicable to large light and/or power service supplied and metered at a single voltage and delivery point. Loads must exceed 100 kW per month. This Schedule cannot be used in conjunction with load management Riders M, T, and I, and Schedule "TOU-P".

RATE:

CUSTOMER CHARGE: $85.00 per month

DEMAND CHARGE - (To be added to Customer and Energy Charge)

Priority Peak	- per kW of billing demand	$12.75/kW
Mid-Peak	- per kW of billing demand	$9.00/kW

The customer shall be billed the Priority Peak demand charge if his maximum measured kW demand for the billing period occurs during the priority peak period. If the customer's maximum measured kW demand for the billing period occurs during the Mid-Peak period, the Mid-Peak demand charge will apply. If the customer's maximum kW demand during the Priority Peak period is equal to his maximum kW demand during the Mid-Peak period, the Priority Peak demand charge shall apply.

ENERGY CHARGE: (To be added to Customer Charge)

Priority Peak Period	- per kWhr	21.2556 ¢/kWhr
Mid-Peak Period	- per kWhr	19.2556 ¢/kWhr
Off-Peak Period	- per kWhr	9.2556 ¢/kWhr

SHEET NO. 138A
Effective

MOLOKAI DIVISION

SCHEDULE TOU-P - (continued)

MINIMUM CHARGE:

The minimum charge per month shall be the sum of the Customer Charge and the Demand Charge. The Demand Charge shall be computed with the above demand charge applied to kilowatts of demand. The kilowatts of demand for the minimum charge calculation each month shall not be less than 100 kW.

TIME-OF-USE RATING PERIODS:

The time-of-use rating periods shall be as follows:

Priority Peak:	5:00 p.m. - 9:00 p.m., Monday - Friday
Mid-Peak:	7:00 a.m. - 5:00 p.m., Monday - Friday
	7:00 a.m. - 9:00 p.m., Saturday - Sunday
Off-Peak:	9:00 p.m. - 7:00 a.m., Daily

DETERMINATION OF TIME-OF-USE ENERGY AND DEMAND:

The Company shall install a time-of-use meter to measure the customer's kilowatthour consumption and kilowatt load during the time-of-use rating periods. The maximum demand for the rating periods for each month shall be the maximum average load in kilowatts during any fifteen-minute period as indicated by a time-of-use meter. The kilowatts of billing demand for each month shall be the maximum measured demand outside of the Off-Peak hours, but not less than 100 kW.

Power Factor:

The above energy and demand charges are based upon an average monthly power factor of 85%. For each 1% the average power factor is above or below 85%, the monthly energy and demand charges as computed under the above rates shall be decreased or increased, respectively, by 0.10%.

SHEET NO. 138B
Effective

MOLOKAI DIVISION

SCHEDULE TOU-P - (continued)

Power Factor - continued:

The average monthly power factor will be determined from the readings of a kWhr meter and kvarh meter, and will be computed to the nearest whole percent and not exceeding 100% for the purpose of computing the adjustment. The kvarh meter shall be ratcheted to prevent reversal in the event the power factor is leading at any time.

Supply Voltage Delivery:

If the customer takes delivery at the Company's supply line voltage, the demand and energy charges will be decreased as follows:

Transmission voltage supplied without further transformation	-4.4%
Distribution voltage supplied without further transformation	-1.1%

Metering will normally be at the delivery voltage. When the customer's transformers are adjacent to the delivery point, the customer may elect to be metered at a single point on the secondary side of his transformers where such point is approved by the Company. When the energy is metered on the secondary side of the customer's transformers, the above decreases will be 3.8% and 0.5%, respectively.

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer, Demand, and Energy charges.

Integrated Resource Planning Cost Recovery Provision:

The Integrated Resource Planning Surcharge shall be added to the Customer, Demand, and Energy charges, and energy cost adjustment.

Rules and Regulations:

Service supplied under this rate shall be subject to the Rules and Regulations of the Company.

Hawaiian Electric Company, Inc.

SCHEDULE OF OUTSTANDING ISSUES OF PREFERRED STOCK,
LONG-TERM DEBT AND HYBRID SECURITIES
FOR INCORPORATION BY REFERENCE
As of September 30, 2008

Year Issued	Description	Total Par Value	Docket No. and Date	Commission Decision & Order and Date
Preferred Stock				
1945	Series C, 4 1/4% 150,000 shares	$ 3,000,000	888 7/11/1945	75-482 7/21/1945
1948	Series D, 5% 50,000 shares	1,000,000	993 3/17/1948	98-589 6/24/1948
1950	Series E, 5% 150,000 shares	3,000,000	1027 3/4/1949	107-625 5/9/1949
1960	Series H, 5 1/4% 250,000 shares	5,000,000	1414 5/27/1960	1012 7/21/1960
1961	Series I, 5% 89,657 shares	1,793,140	1460 6/21/1961	1067 7/21/1961
1962	Series J, 4 3/4% 250,000 shares	5,000,000	1496 3/21/1962	1100 4/17/1962
1964	Series K, 4.65% 175,000 shares	3,500,000	1546 4/30/1963	1203 5/16/1963
TOTAL OUTSTANDING 9/30/08		$ 22,293,140		

Hawaiian Electric Company, Inc.

SCHEDULE OF OUTSTANDING ISSUES OF PREFERRED STOCK,
LONG-TERM DEBT AND HYBRID SECURITIES
FOR INCORPORATION BY REFERENCE
As of September 30, 2008

Year Issued	Description	Issue Amount	Docket No. and Date	Commission Decision & Order and Date
Long-Term Debt				
State of Hawaii - Special Purpose Revenue Bonds				
1993	5.45% Series 1993 due 2023	$ 50,000,000	7624 / 6797 2/26/1993	12651 10/6/1993
1997	5.65% Series 1997A due 2027	50,000,000	95-0096 / 96-0381 4/28/95 & 9/30/96	PUC approval 9/30/1997
1998	4.95% Refunding Series 1998A due 2012	42,580,000	97-0351 9/29/1997	16145 1/5/1998
1999	5.75% Refunding Series 1999B due 2018	30,000,000	99-0060 3/12/1999	17057 6/29/1999
1999	6.20% Series 1999C due 2029	35,000,000	99-0120 5/17/1999	17253 9/27/1999
1999	6.15% Refunding Series 1999D due 2020	16,000,000	99-0060 3/12/1999	17057 6/29/1999
2000	5.70% Refunding Series 2000 due 2020	46,000,000	00-0120 4/14/2000	18151 10/20/2000
2002	5.10% Series 2002A due 2032	40,000,000	99-0120 5/17/2002	19525 8/15/2002
2003	5.00% Refunding Series 2003B due 2022	40,000,000	03-0045 2/21/2003	20120 4/14/2003
2005	4.80% Refunding Series 2005A due 2025	40,000,000	04-0303 10/15/2004	21497 12/17/2004
2007	4.65% Series 2007A due 2037	100,000,000	05-0330 12/29/2005	23292 3/9/2007
2007	4.60% Refunding Series 2007B due 2026	62,000,000	2006-0383 9/21/2006	23100 12/4/2006
TOTAL OUTSTANDING 9/30/08		$ 551,580,000		

Hawaiian Electric Company, Inc.

SCHEDULE OF OUTSTANDING ISSUES OF PREFERRED STOCK,
LONG-TERM DEBT AND HYBRID SECURITIES
FOR INCORPORATION BY REFERENCE
As of September 30, 2008

Year Issued	Description	Issue Amount	Docket No. and Date	Commission Decision & Order and Date
Trust Preferred Securities				
2004	6.50% Junior Subordinated Deferrable Interest Debentures, Series 2004 (2004 QUIPS) due 2034	$ 31,546,400	03-0409 12/8/2003	20803 2/13/2004 Amended by 20812 2/24/2004
TOTAL OUTSTANDING 9/30/08		$ 31,546,400		

Hawaii Electric Light Company, Inc.

SCHEDULE OF OUTSTANDING ISSUES OF PREFERRED STOCK,
LONG-TERM DEBT AND HYBRID SECURITIES
FOR INCORPORATION BY REFERENCE
As of September 30, 2008

Year Issued	Description	Total Par Value	Docket No. and Date	Commission Decision & Order and Date
Preferred Stock				
1993	Series G, 7 5/8% 70,000 shares	$ 7,000,000	7624 2/26/1993	12651 10/6/1993
TOTAL OUTSTANDING 9/30/08		$ 7,000,000		

Hawaii Electric Light Company, Inc.

SCHEDULE OF OUTSTANDING ISSUES OF PREFERRED STOCK,
LONG-TERM DEBT AND HYBRID SECURITIES
FOR INCORPORATION BY REFERENCE
As of September 30, 2008

Year Issued	Description	Issue Amount	Docket No. and Date	Commission Decision & Order and Date
Long-Term Debt				
State of Hawaii - Special Purpose Revenue Bonds				
1993	5.45% Series 1993 due 2023	$ 20,000,000	7624 / 6797 2/26/1993	12651 10/6/1993
1997	5.65% Series 1997A due 2027	30,000,000	95-0096 / 96-0381 4/28/95 & 9/30/96	PUC approval 9/30/1997
1998	4.95% Refunding Series 1998A due 2012	7,200,000	97-0351 9/29/1997	16145 1/5/1998
1999	5.50% Refunding Series 1999A due 2014	11,400,000	99-0060 3/12/1999	17057 6/29/1999
1999	5.75% Refunding Series 1999B due 2018	11,000,000	99-0060 3/12/1999	17057 6/29/1999
1999	6.15% Refunding Series 1999D due 2020	3,000,000	99-0060 3/12/1999	17057 6/29/1999
2003	4.75% Refunding Series 2003A due 2020	14,000,000	03-0045 2/21/2003	20120 4/14/2003
2003	5.00% Refunding Series 2003B due 2022	12,000,000	03-0045 2/21/2003	20120 4/14/2003
2005	4.80% Refunding Series 2005A due 2025	5,000,000	04-0303 10/15/2004	21497 12/17/2004
2007	4.65% Series 2007A due 2037	20,000,000	05-0330 12/29/2005	23292 3/9/2007
2007	4.60% Refunding Series 2007B due 2026	8,000,000	2006-0383 9/21/2006	23100 12/4/2006
TOTAL OUTSTANDING 9/30/08		$ 141,600,000		

Hawaii Electric Light Company, Inc.

SCHEDULE OF OUTSTANDING ISSUES OF PREFERRED STOCK,
LONG-TERM DEBT AND HYBRID SECURITIES
FOR INCORPORATION BY REFERENCE
As of September 30, 2008

Year Issued	Description	Issue Amount	Docket No. and Date	Commission Decision & Order and Date
Trust Preferred Securities				
2004	6.50% Junior Subordinated Deferrable Interest Debentures, Series 2004 (2004 QUIPS) due 2034	$ 10,000,000	03-0409 12/8/2003	20803 2/13/2004 Amended by 20812 2/24/2004
TOTAL OUTSTANDING 9/30/08		$ 10,000,000		

Maui Electric Company, Limited

SCHEDULE OF OUTSTANDING ISSUES OF PREFERRED STOCK,
LONG-TERM DEBT AND HYBRID SECURITIES
FOR INCORPORATION BY REFERENCE
As of September 30, 2008

Year Issued	Description	Total Par Value	Docket No. and Date	Commission Decision & Order and Date
Preferred Stock				
1993	Series H, 7 5/8% 50,000 shares	$ 5,000,000	7624 2/26/1993	12651 10/6/1993
TOTAL OUTSTANDING 9/30/08		$ 5,000,000		

Maui Electric Company, Limited

SCHEDULE OF OUTSTANDING ISSUES OF PREFERRED STOCK,
LONG-TERM DEBT AND HYBRID SECURITIES
FOR INCORPORATION BY REFERENCE
As of September 30, 2008

Year Issued	Description	Issue Amount	Docket No. and Date	Commission Decision & Order and Date
Long-Term Debt				
State of Hawaii - Special Purpose Revenue Bonds				
1993	5.45% Series 1993 due 2023	$ 30,000,000	7624 / 6797 2/26/1993	12651 10/6/1993
1997	5.65% Series 1997A due 2027	20,000,000	95-0096 / 96-0381 4/28/95 & 9/30/96	PUC approval 9/30/1997
1998	4.95% Refunding Series 1998A due 2012	7,720,000	97-0351 9/29/1997	16145 1/5/1998
1999	5.75% Refunding Series 1999B due 2018	9,000,000	99-0060 3/12/1999	17057 6/29/1999
1999	6.15% Series Refunding 1999D due 2020	1,000,000	99-0060 3/12/1999	17057 6/29/1999
2000	5.70% Refunding Series 2000 due 2020	20,000,000	00-0120 4/14/2000	18151 10/20/2000
2005	4.80% Refunding Series 2005A due 2025	2,000,000	04-0303 10/15/2004	21497 12/17/2004
2007	4.65% Series 2007A due 2037	20,000,000	05-0330 12/29/2005	23292 3/9/2007
2007	4.60% Refunding Series 2007B due 2026	55,000,000	2006-0383 9/21/2006	23100 12/4/2006
TOTAL OUTSTANDING 9/30/08		$ 164,720,000		

Maui Electric Company, Limited

SCHEDULE OF OUTSTANDING ISSUES OF PREFERRED STOCK,
LONG-TERM DEBT AND HYBRID SECURITIES
FOR INCORPORATION BY REFERENCE
As of September 30, 2008

Year Issued	Description	Issue Amount	Docket No. and Date	Commission Decision & Order and Date
Trust Preferred Securities				
2004	6.50% Junior Subordinated Deferrable Interest Debentures, Series 2004 (2004 QUIPS) due 2034	$ 10,000,000	03-0409 12/8/2003	20803 2/13/2004 Amended by 20812 2/24/2004
TOTAL OUTSTANDING 9/30/08		$ 10,000,000		

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

In the Matter of the Application of	)	
	)	
HAWAIIAN ELECTRIC COMPANY, INC.	)	Docket No.
HAWAII ELECTRIC LIGHT COMPANY, INC.	)	
MAUI ELECTRIC COMPANY, LIMITED	)	
	)	
For Approval of the Advanced Meter Infrastructure	)	
(AMI) Project and Request to Commit	)	
Capital Funds, to Defer and Amortize	)	
Software Development Costs, to Begin	)	
Installation of Meters and Implement Time-Of-Use	)	
Rates, for Approval of Accounting and Ratemaking	)	
Treatment, and other matters.	)	

CERTIFICATE OF SERVICE

I hereby certify that I have this date served two copies of the foregoing Application, together with this Certificate of Service, by making personal service to the following and at the following address:

Division of Consumer Advocacy
Department of Commerce and Consumer Affairs
335 Merchant Street, Room 326
Honolulu, Hawaii 96813

DATED: Honolulu, Hawaii, December 1, 2008

HAWAIIAN ELECTRIC COMPANY, INC.

Irene Sekiya

Irene Sekiya